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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

INTEGRATED RESOURCE PLANNING REPORT OF KENTUCKY POWER COMPANY TO THE KENTUCKY PUBIC SERVICE COMMISSION	)) Case No. 2013-00475)

KENTUCKY POWER COMPANY RESPONSES TO SIERRA CLUB'S SUPPLEMENTAL SET OF DATA REQUESTS

March 21, 2014

VERIFICATION

The undersigned, Will K. Castle, being duly sworn, deposes and says he is the Director Resource and DSM Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

Will K Castle

Will K. Castle

STATE OF OHIO)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State by Will K. Castle, this the 13 day of March 2014.

Kristina Woods

Notary Public

NOTARIAL SEAL STATE OF OHIO

Kristina L. Woods
Notary Public, State of Ohio
My Commission Expires 03-07-2016

My Commission Expires: 3-7-2016

VERIFICATION

The undersigned, John F. Torpey, being duly sworn, deposes and says he is the Director Integrated Resource Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

John F Torpey

John F. Torpey

STATE OF OHIO)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John F. Torpey, this the 14th day of March 2014.

Josephine Coner

Notary Public

JOSEPHINE CONER
Notary Public, State of Ohio
My Commission Expires 09-20-16

My Commission Expires: 09-20-2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) Case No. 2013-00475
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 19th day of March 2014.

Judy K. Rosquist 481393

Notary Public

My Commission Expires: January 23, 2017

KENTUCKY POWER COMPANY

REQUEST

Refer to the "Confidential Price Forecasts" table starting on page 235 of Volume D of the Confidential Supplement to the IRP produced as Confidential Attachment 4 to KPC's response to SC 1-2.

a. Identify the discount and/or inflation rates that were used to generate the figures in this table.

b. Identify and produce the source(s) of the forecasted [redacted] identified therein.

c. State whether any of the price forecasts identified therein factor in a price on carbon emissions during any of the years of the forecast.

   i. If so, identify the carbon price used for each year of the forecast, and the basis for such price.

RESPONSE

a. The implicit GDP price deflator was used to account for inflation in the prices provided in Volume D of the Confidential Supplement. Please see Attachment 1 to this response for the annual average deflator used.

b. The wholesale electricity prices reflect the average price for Kentucky Power's wholesale customers. The forecast is developed by the Company for use in the load forecast and is derived based on the Company's financial model and EIA long-term projections.

c. The price of carbon emissions is not explicitly accounted for in the prices used in the load forecast.

WITNESS: William K Castle

Implicit GDP Price Deflator
(Index 2005=100)

Year	Index
1984	59.9
1985	61.7
1986	63.1
1987	64.8
1988	67.0
1989	69.6
1990	72.3
1991	74.8
1992	76.6
1993	78.3
1994	79.9
1995	81.6
1996	83.2
1997	84.6
1998	85.6
1999	86.8
2000	88.7
2001	90.7
2002	92.2
2003	94.1
2004	96.8
2005	100.0
2006	103.2
2007	106.2
2008	108.6
2009	109.5
2010	111.0
2011	113.4
2012	115.5
2013	118.0
2014	120.6
2015	123.4
2016	125.8
2017	128.1
2018	130.7
2019	133.2
2020	135.7
2021	138.3
2022	141.0
2023	143.7
2024	146.5
2025	149.4

Implicit GDP Price Deflator
(Index 2005=100)

Year	Index
2026	152.3
2027	155.1
2028	158.0
2029	160.8
2030	163.7
2031	166.5
2032	169.4
2033	172.3
2034	175.3
2035	178.3
2036	181.3
2037	184.4
2038	187.6
2039	191.0
2040	194.6
2041	198.4
2042	202.6

Souces: Bureau Economic Analysis
Moody's Analytics

Kentucky Power Company

REQUEST

Refer to Exhibit 4-4 of Volume D of the Confidential Supplement to the IRP produced as Confidential Attachment 4 to KPC's response to SC 1-2.

a. With regards to the [redacted] found on page 1 of Exhibit 4-4, explain why:

[redacted]

[redacted]

RESPONSE

i. The fuel costs for Mitchell through 2016 are based upon AEP's current knowledge of coal purchase commitments; beyond 2016, the fuel cost reflects spot market pricing.

ii. In 2026, when Rockport Unit 1 is retrofitted with a FGD, the fuel is switched from a PRB/Eastern blended coal to a lower cost Illinois Basin coal.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Attachment 1 to KPC's response to SC 1-9.

a. State whether the Wyandot Solar worksheet was used in developing Figure 9 on page 97 of the IRP.

   i. If so, explain how.
   ii. If not, explain what role, if any, the Wyandot Solar worksheet played in KPC's evaluation of solar DG or utility-scale solar in the IRP.

b. With regards to the "inputs" tab, identify and produce the basis for the values assigned to each of the following:

   i. Net metering rate
   ii. Solar panel annual degradation
   iii. Capacity factor
   iv. Effective capacity
   v. Panel life
   vi. Discounted value of energy
   vii. Discounted value of capacity

c. State whether the forecasted energy and capacity values used in the analysis reflected in Attachment 1assumed a price on carbon emissions during any of the years of the forecast.

   i. If so, identify the carbon price used for each year of the forecast, and the basis for such price

   ii. If not, explain how the inclusion of a price on carbon would impact the results of the analysis.

RESPONSE

a. (i) The Wyandot solar shape served as the basis for evaluating solar resources potentially available to Kentucky Power in the future. The Wyandot solar shape provides a reasonable approximation for the hourly generation of solar panels in Kentucky. This generation profile was compared to the hourly energy costs in PJM as well as the coincidence with PJM's peak demand to determine its value.

a. (ii) N/A

b. (i) approximate prevailing retail rate for Kentucky Power residential and commercial customers.

b. (ii) See "Photovoltaic Degradation Rates - An Analytical Review" from NREL www.nrel.gov/docs/fy12osti/51664.pdf

b. (iii) Wyandot shape

b. (iv) PJM assigned value.

b. (v) most industry warranties are 20-25 years, but it is reasonable to assume a 30 year life, with annual degradation.

b. (vi) the discounted value of energy is the present value of the 30 years of energy produced

b. (vii) the discounted value of capacity is the present value of the 30 years of coincident peak reduction

c. The prices include an assumption for CO_2 starting in 2022. The rationale for the carbon price assumption is included in 4.6.5 of the IRP.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 10. Regarding KPC's statement that utility-owned (or purchased) solar generation is expected to become economic around 2020:

a. Explain how "economic" is defined in the referenced statement, and each cost and benefit that was factored into your assessment.

b. Explain the factual basis for this conclusion, and identify any assumptions made in reaching that conclusion.

c. Explain how the information in SC 1-9 Attachment 1 was used to reach this conclusion.

RESPONSE

a. "Economic" means that the present value of revenue requirements for the solar resource is lower than a (PJM) market alternative. The costs of solar included the installed capital cost. The benefits are the value of the energy and capacity generated by the resource.

b. The analysis relies on (forecasted) PJM values for thirty years into the future as well as installed costs of solar five years in the future. It also utilizes solar operating characteristics that are similar to operating characteristics currently being experienced.

c. Please see the "inputs" tab of SC 1-9 Attachment 1 where the present values of the PJM costs and the cost to construct intersect.

In 2019, the PJM value of solar exceeds the cost to construct it, thus the statement that it becomes economic "around 2020."

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 11. Describe the hourly information that is necessary to model an expansion of current EE programs.

RESPONSE

To model the current programs with precision, hourly load shapes for the end uses of the measures that make up the programs would be required. The hourly load shapes that Kentucky Power has can approximate prospective programs. Those same load shapes could be used to approximate current programs as well, but Kentucky Power did not want to leave the Commission or the Parties with the impression that data exists to model the expansion of our current programs with precision.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to SC 1-14 Confidential Attachment 1. On the [redacted]

a. Identify [redacted] refer to.

b. Identify and produce the source of [redacted]

c. State whether the identified [redacted] were for a single year or multiple years, and identify such year or years.

d. Identify what [redacted]

e. State whether KPC contends that the identified [redacted]

i. If so, explain the basis for such contention.

RESPONSE

a. "Peak Load Contribution" and "High Previous Demand"

b. PJM provides the estimated load reductions.

c. PLC is for the current year PJM deliver year (2013/2014) and HPD was for trailing 12 months.

d. These numbers are for loads registered with PJM that are within AEP operating companies service territories. Indiana: Indiana Michigan Power; Ohio: AEP Ohio; Virginia: Appalachian Power Company; West Virginia: Appalachian Power Company.

e. Please see discussion of methodology and interpretation of results on pgs 91-92 of Kentucky Power's 2013 IRP Report.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 19.

a. Please state what the data on page 1 of SC 1-19 Attachment 1 represents. For example, does it represent Efficiency Vermont data or Efficiency Vermont data adjusted by the Company to fit the climate of its service territory?

b. If the data represents Efficiency Vermont data adjusted by the Company to fit the climate of its service territory, please provide the underlying Efficiency Vermont data.

c. If the data represents Efficiency Vermont data, please provide the information presented on page 1 of SC 1-19 Attachment , as adjusted by the Company to fit the climate of its service territory.

d. Please provide the source document containing the Efficiency Vermont data presented in SC 1-19 Attachment 1. Please state whether this data is available on Efficiency Vermont's website. If so, please provide the hyperlink.

e. With regards to the "calculations" referenced in part b of KPC's response to Sierra Club request 19, produce any workpapers in which such calculations were made in electronic, machine readable format with formulas intact.

RESPONSE

a. The first 9 columns are Efficiency Vermont data; subsequent columns show the adjustments made to comport with the climate of Kentucky.
b. See response to a.
c. See response to a.
d. See Efficiency Vermont's 2011 Annual Report, pages 53 and 55. http://www.efficiencyvermont.com/About-Us/Oversight-Reports-Plans/Annual-Reports-amp-Plans
e. Please see Attachment 1 to this response.

WITNESS: William K Castle

Air Conditioning Energy Consumed

	CDD	HDD	
Little Rock	2,086	3,084	
Fayetteville	1,439	4,166	
Texarkana	2,138	2,893	
Shreveport	2,405	2,251	
average	2,017	3,099	4746
Burlington, VT	489	7,665	
Montpelier, VT	225	8,245	
Boston, MA	777	5,630	
	497	7,180	510
Seattle, WA	173	4,797	
Los Angeles, CA	679	1,274	
Monterey, CA	74	3,092	
San Diego, CA	866	1,063	
San Francisco, CA	142	2,862	
	387	2,618	748
Roanoke, VA	978	4,284	
Charleston, WV	1,134	4,644	
	1,056	4,464	

CDD	End Use Consumption
2107	4746
497	510
387	748

http://cdo.ncdc.noaa.gov/cgi-bin/climatenormals/climatenormals.pl?directive=prod_select2&prodtype=CLIM81&subnum=

	Central A/C	Electric Furnace
Pacific	38%	23%
New England	15%	6%
West South Central	73%	45%
SWEPCO	75%	45%

4746	0.75
510	0.15
748	0.38

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 20.

a. Please explain which data in SC 1-19 Attachment 1 comprise KPC's incremental cost assumptions for energy efficiency.

b. Please explain how the Company accounted for the difference between the end use categories in SC 1-19 Attachment 1 and those presented in Figure 8 on page 96 of the IRP.

RESPONSE

a. See column labeled: $/First Year Savings

b. The end use names from Vermont programs were mapped to end-use categories collected by Kentucky Power. Please see Attachment 1 to this response.

WITNESS: William K Castle

Mapping

Vermont Program Category	**Kentucky End-use**
<u>Commercial</u>	
A/C	HVAC
Hot Water	Cooking & Laundry
Industrial Process	Misc
Lighting	Lighting
Motors	Misc
Refrigeration	Refrigeration
All Other	Misc
<u>Residential</u>	
A/C	Cooling
Coooking and Laundry	Appliance
Lighting	Lighting
Refrigeration	Appliance
Space Heat	Heating
All Other	Misc

KENTUCKY POWER COMPANY

REQUEST

Refer to KPC's response to Sierra Club request no. 23 and pages 130 to 135 of the IRP.

a. Referring to KPC's response to 23.a and page 134 of the IRP, produce the modeling input files and workpapers (in electronic, machine readable format with formulas intact) used for analyzing the "nearer-term" wind resource opportunity

b. Produce the modeling input files and workpapers (in electronic, machine readable format with formulas intact) used for analyzing wind resource opportunities for periods beyond 2017

c. Referring to Figure 15 on page 135 of the IRP, identify and produce any studies, analyses, or workpapers upon which the utility wind cost assumptions are based

d. Referring to KPC's response to 23.b, produce the workpapers, source documents, and underlying data used to generate the figures reflected in "Figure 12: Solar Panel Installed Cost" on page 131 of the IRP.

RESPONSE

a. Please see attached CD for this response.

b. Please see Attachment 2 to this response.

c. Please see Attachment 3 to this response.

d. The documents used to determine the solar cost assumptions are licensed and cannot be duplicated. The Company will produce the documents for review at its Frankfort, Kentucky offices, located at 101A Enterprise Drive, at a mutually agreed time.

WITNESS: John F Torpey

Plexos Addition of Utility Wind Calculation

	Plexos Input Build Cost ($/kW)	Units Built	Maximum Capacity (MW)	Build Cost ($000)	WACC (%)	Inflation Rate (%)	Economic Life (Years)	Tax Rate (%)	Depreciation Method	Equation 9: Annuity Calculation ($000)	SLD Method Annuity Calculation ($000)	Capacity Credit Discounted Annuity ($000)	Discounted vs SLD Annuity ($000)	SLD vs Discounted Annuity (%)
2014	2015	1	50.00	100,750	15.000%	2.500%	30	40.00%	SLD	15,344	14,184	14,171	14	0
2015	1975	1	50.00	98,750	15.000%	2.500%	30	40.00%	SLD	15,040	13,903	13,912	(9)	(0)
2016	1940	1	50.00	97,000	15.000%	2.500%	30	40.00%	SLD	14,773	13,656	13,657	(1)	(0)
2017	1900	1	50.00	95,000	15.000%	2.500%	30	40.00%	SLD	14,469	13,375	13,385	(10)	(0)
2018	1865	1	50.00	93,250	15.000%	2.500%	30	40.00%	SLD	14,202	13,129	13,122	7	0
2019	1825	1	50.00	91,250	15.000%	2.500%	30	40.00%	SLD	13,897	12,847	12,863	(16)	(0)
2020	1790	1	50.00	89,500	15.000%	2.500%	30	40.00%	SLD	13,631	12,601	12,601	(1)	(0)
2021	1750	1	50.00	87,500	15.000%	2.500%	30	40.00%	SLD	13,326	12,319	12,337	(18)	(0)
2022	1715	1	50.00	85,750	15.000%	2.500%	30	40.00%	SLD	13,060	12,073	12,071	2	0
2023	1680	1	50.00	84,000	15.000%	2.500%	30	40.00%	SLD	12,793	11,826	11,802	24	0
2024	1640	1	50.00	82,000	15.000%	2.500%	30	40.00%	SLD	12,489	11,545	11,531	13	0
2025	1600	1	50.00	80,000	15.000%	2.500%	30	40.00%	SLD	12,184	11,263	11,259	4	0
2026	1560	1	50.00	78,000	15.000%	2.500%	30	40.00%	SLD	11,879	10,981	10,985	(4)	(0)
2027	1520	1	50.00	76,000	15.000%	2.500%	30	40.00%	SLD	11,575	10,700	10,710	(10)	(0)
2028	1480	1	50.00	74,000	15.000%	2.500%	30	40.00%	SLD	11,270	10,418	10,434	(15)	(0)
2029	1440	1	50.00	72,000	15.000%	2.500%	30	40.00%	SLD	10,966	10,137	10,157	(20)	(0)
2030	1400	1	50.00	70,000	15.000%	2.500%	30	40.00%	SLD	10,661	9,855	9,877	(22)	(0)
2031	1360	1	50.00	68,000	15.000%	2.500%	30	40.00%	SLD	10,356	9,574	9,595	(21)	(0)
2032	1320	1	50.00	66,000	15.000%	2.500%	30	40.00%	SLD	10,052	9,292	9,303	(11)	(0)
2033	1280	1	50.00	64,000	15.000%	2.500%	30	40.00%	SLD	9,747	9,010	9,011	(0)	(0)
2034	1240	1	50.00	62,000	15.000%	2.500%	30	40.00%	SLD	9,443	8,729	8,718	11	0
2035	1200	1	50.00	60,000	15.000%	2.500%	30	40.00%	SLD	9,138	8,447	8,418	29	0
2036	1155	1	50.00	57,750	15.000%	2.500%	30	40.00%	SLD	8,795	8,131	8,111	19	0
2037	1110	1	50.00	55,500	15.000%	2.500%	30	40.00%	SLD	8,453	7,814	7,804	10	0
2038	1065	1	50.00	53,250	15.000%	2.500%	30	40.00%	SLD	8,110	7,497	7,489	8	0
2039	1020	1	50.00	51,000	15.000%	2.500%	30	40.00%	SLD	7,767	7,180	7,167	13	0
2040	975	1	50.00	48,750	15.000%	2.500%	30	40.00%	SLD	7,425	6,863	6,845	19	0

Adjustment Factor 0.089471

Strategist Levelized Carrying Charge ($000) =
Plexos Difference from Strategist ($000) =
Plexos Difference from Strategist (%) =

Real Annuity Factor = 6.566
Nominal Annuity Factor = 5.669
SLD Factor = 0.140788305

Plexos Addition of Utility Wind Calculation

	Plexos Input Build Cost ($/kW)	Units Built	Maximum Capacity (MW)	Build Cost ($000)	WACC (%)	Inflation Rate (%)	Economic Life (Years)	Tax Rate (%)	Depreciation Method	Equation 9: Annuity Calculation ($000)	Strategist Annuity Calculation ($000)	No Capacity Credit Annuity Calculation ($000)	LT Plan Calculated Capacity Credit Discounted Annuity ($000)	Annual Capacity Credit ($000)	Strategist vs LT Plan ($000)
2014	2100	1	50.00	105,000	15.000%	2.500%	30	40.00%	SLD	15,992	14,774	14,783	14,184	598	9
2015	2070	1	50.00	103,500	15.000%	2.500%	30	40.00%	SLD	15,763	14,566	14,572	13,903	669	6
2016	2040	1	50.00	102,000	15.000%	2.500%	30	40.00%	SLD	15,535	14,356	14,360	13,656	704	5
2017	2010	1	50.00	100,500	15.000%	2.500%	30	40.00%	SLD	15,306	14,142	14,149	13,375	774	7
2018	1979	1	50.00	98,950	15.000%	2.500%	30	40.00%	SLD	15,070	13,926	13,931	13,129	802	5
2019	1948	1	50.00	97,400	15.000%	2.500%	30	40.00%	SLD	14,834	13,706	13,713	12,847	866	7
2020	1916	1	50.00	95,800	15.000%	2.500%	30	40.00%	SLD	14,590	13,484	13,488	12,601	887	4
2021	1884	1	50.00	94,200	15.000%	2.500%	30	40.00%	SLD	14,347	13,258	13,262	12,319	943	4
2022	1852	1	50.00	92,600	15.000%	2.500%	30	40.00%	SLD	14,103	13,029	13,037	12,073	964	8
2023	1819	1	50.00	90,950	15.000%	2.500%	30	40.00%	SLD	13,852	12,797	12,805	11,826	978	8
2024	1785	1	50.00	89,250	15.000%	2.500%	30	40.00%	SLD	13,593	12,562	12,565	11,545	1,021	4
2025	1751	1	50.00	87,550	15.000%	2.500%	30	40.00%	SLD	13,334	12,323	12,326	11,263	1,063	3
2026	1717	1	50.00	85,850	15.000%	2.500%	30	40.00%	SLD	13,075	12,081	12,087	10,981	1,105	5
2027	1682	1	50.00	84,100	15.000%	2.500%	30	40.00%	SLD	12,808	11,836	11,840	10,700	1,140	4
2028	1647	1	50.00	82,350	15.000%	2.500%	30	40.00%	SLD	12,542	11,587	11,594	10,418	1,176	7
2029	1611	1	50.00	80,550	15.000%	2.500%	30	40.00%	SLD	12,268	11,335	11,340	10,137	1,204	6
2030	1575	1	50.00	78,750	15.000%	2.500%	30	40.00%	SLD	11,994	11,079	11,087	9,855	1,232	8
2031	1538	1	50.00	76,900	15.000%	2.500%	30	40.00%	SLD	11,712	10,821	10,827	9,574	1,253	5
2032	1500	1	50.00	75,000	15.000%	2.500%	30	40.00%	SLD	11,423	10,554	10,559	9,292	1,267	5
2033	1462	1	50.00	73,100	15.000%	2.500%	30	40.00%	SLD	11,133	10,287	10,292	9,010	1,281	4
2034	1424	1	50.00	71,200	15.000%	2.500%	30	40.00%	SLD	10,844	10,020	10,024	8,729	1,295	4
2035	1385	1	50.00	69,250	15.000%	2.500%	30	40.00%	SLD	10,547	9,747	9,750	8,447	1,302	3
2036	1346	1	50.00	67,300	15.000%	2.500%	30	40.00%	SLD	10,250	9,466	9,475	8,131	1,345	9
2037	1306	1	50.00	65,300	15.000%	2.500%	30	40.00%	SLD	9,945	9,186	9,193	7,814	1,380	8
2038	1265	1	50.00	63,250	15.000%	2.500%	30	40.00%	SLD	9,633	8,899	8,905	7,497	1,408	6
2039	1223	1	50.00	61,150	15.000%	2.500%	30	40.00%	SLD	9,313	8,605	8,609	7,180	1,429	4
2040	1181	1	50.00	59,050	15.000%	2.500%	30	40.00%	SLD	8,993	8,311	8,314	6,863	1,450	2

Year	Build Cost ($/kW)	Annual Fixed Charge ($000)	Levelized Capacity Credit Discount [1] ($/kW-yr)	Levelized Capacity Credit Discount ($000)	Discounted Annual Fixed Charge ($000)
2014	2,213	14,773.54	12.05	602.66	14,171
2015	2,182	14,565.99	13.09	654.35	13,912
2016	2,150	14,355.53	13.96	698.10	13,657
2017	2,118	14,142.11	15.15	757.27	13,385
2018	2,086	13,925.70	16.08	804.05	13,122
2019	2,053	13,706.24	16.87	843.48	12,863
2020	2,020	13,483.70	17.65	882.46	12,601
2021	1,986	13,258.04	18.42	920.87	12,337
2022	1,952	13,029.20	19.17	958.48	12,071
2023	1,917	12,797.15	19.90	995.07	11,802
2024	1,882	12,561.84	20.61	1,030.39	11,531
2025	1,846	12,323.22	21.28	1,064.14	11,259
2026	1,810	12,081.25	21.92	1,096.11	10,985
2027	1,773	11,835.89	22.52	1,125.96	10,710
2028	1,736	11,587.07	23.07	1,153.34	10,434
2029	1,698	11,334.76	23.56	1,177.84	10,157
2030	1,660	11,078.91	24.04	1,201.91	9,877
2031	1,621	10,821.47	24.53	1,226.40	9,595
2032	1,581	10,554.43	25.03	1,251.31	9,303
2033	1,541	10,287.40	25.53	1,276.64	9,011
2034	1,501	10,020.37	26.05	1,302.38	8,718
2035	1,460	9,746.66	26.57	1,328.54	8,418
2036	1,418	9,466.28	27.10	1,355.11	8,111
2037	1,376	9,185.90	27.64	1,382.21	7,804
2038	1,333	8,898.84	28.20	1,409.86	7,489
2039	1,289	8,605.10	28.76	1,438.05	7,167
2040	1,245	8,311.37	29.34	1,466.82	6,845

(1) Source is Kentucky Wind RFP Screener.xls

Wind Capacity (MW)	50
Starting Cost ($/kW)	2213
Annual Discount Factor	0.01404846
Levelized Fixed Charge Rate	13.35%

Year	Build Cost Discount (%)
2014	0.0%
2015	1.4%
2016	2.8%
2017	4.3%
2018	5.7%
2019	7.2%
2020	8.7%
2021	10.3%
2022	11.8%
2023	13.4%
2024	15.0%
2025	16.6%
2026	18.2%
2027	19.9%
2028	21.6%
2029	23.3%
2030	25.0%
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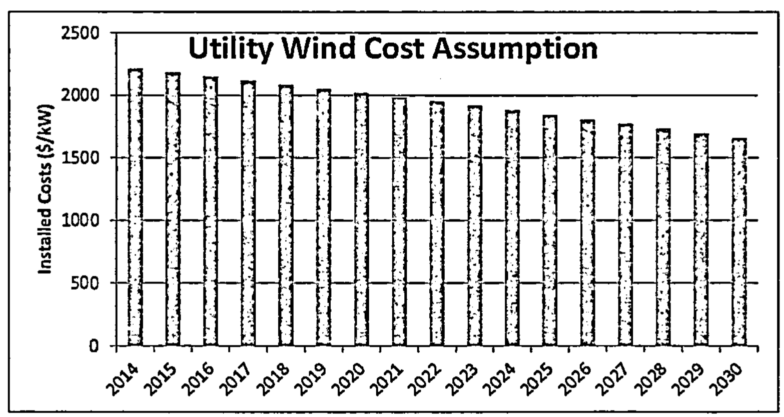

The Past and Future Cost of Wind Energy

Preprint

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National Renewable Energy Laboratory

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Denver, Colorado
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WREF 2012: THE PAST AND FUTURE COST OF WIND ENERGY

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ABSTRACT

The future of wind power will depend on the ability of the industry to continue to achieve cost reductions. To better understand the potential for cost reductions, this report provides a review of historical costs, evaluates near-term market trends, and summarizes the range of projected costs. It also notes potential sources of future cost reductions.

Our findings indicate that steady cost reductions were interrupted between 2004 and 2010, but falling turbine prices are expected to drive a historically low LCOE for current installations. In addition, the majority of studies indicate continued cost reductions on the order of 20%-30% through 2030. Moreover, useful cost projections are likely to benefit from stronger consideration of the interactions between capital cost and performance as well as trends in the quality of the wind resource where projects are located, transmission, grid integration, and other cost variables.

1. INTRODUCTION

Wind power has become a mainstream source of electricity generation around the world. The future of wind power, however, will depend on the ability of the industry to continue to achieve cost reductions and, ultimately, to achieve cost parity with conventional sources of generation across a broad array of contexts and locations.

This summary report, developed as part of the International Energy Agency (IEA) Wind Implementing Agreement Task 26, *The Cost of Wind Energy*, provides a review of historical costs, evaluates near-term market trends, and summarizes projected costs for onshore wind.

2. HISTORICAL TRENDS IN THE COST OF WIND ENERGY

From the 1980s to the early 2000s, average capital costs for wind energy projects declined markedly. In the United States, capital costs were at their lowest level from roughly 2001 to 2004, approximately 65% below costs from the early 1980s [1]. In Denmark, capital costs followed a similar trend, achieving their lowest level in 2003, more than 55% below the levels seen in the early 1980s [2] (Figure 1).

Historical capital cost reductions were coupled with dramatic increases in turbine performance resulting from more advanced turbine components and larger turbines.

Figure 2 illustrates the growth of turbine nameplate capacity, hub height, and rotor diameter over the past 30 years.

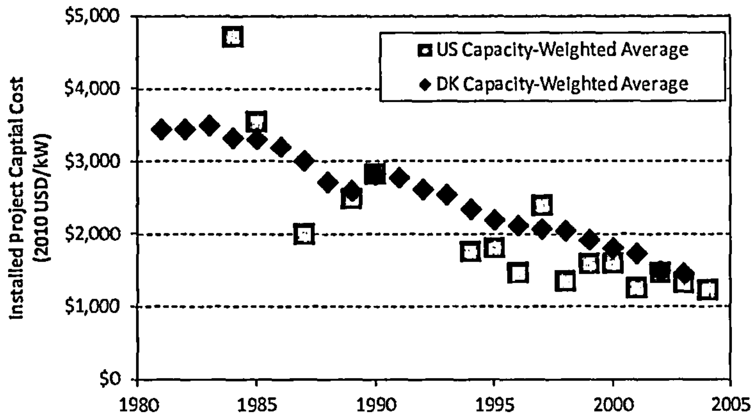


Fig. 1: Capital cost trends in the United States and Denmark between 1980 and 2003 [1-2].

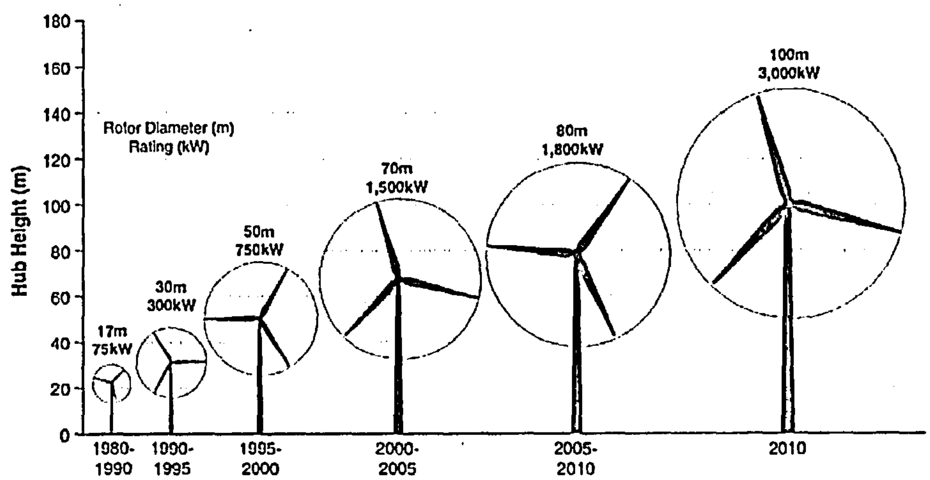


Fig. 2: Representative turbine architectures from 1980 to 2010; Source: NREL.

The combined effects of falling costs and enhanced performance had the impact of dramatically reducing the levelized cost of energy (LCOE) for onshore wind energy between the early 1980s and the early 2000s. Data from three different historical evaluations, including internal analysis by the Lawrence Berkley National Laboratory (LBNL) and the National Renewable Energy Laboratory (NREL), as well as published estimates from Lemming et al. [3] and the Danish Energy Agency (DEA) [4], illustrate that the LCOE of wind power declined by a factor of more than three over this time period (Figure 3) from upwards of $150/MWh in the 1980s and1990s to about $50/MWh in the early 2000s.

The initial period of significant cost reductions came to an end in the early-to-mid 2000s. Data from the United States, Denmark, Spain, and Europe indicate capital cost increases began rising around 2004 and continued to rise through at least 2007–2009 [1-2, 5].

An important exception to this general trend of substantially rising capital costs from 2004 to 2009 was China. Specifically, the emergence of a handful of strong domestic original equipment manufacturers (OEMs) resulted in significantly lower capital costs in China (i.e., $1,100/kW–$1,500/kW [2010 U.S. dollars] in 2008–2009) than witnessed in Europe or the United States [6].

The increase in capital costs observed in most markets from 2004 and 2009 has been largely tied to increases in the price of wind turbines [5, 7]. Turbine price increases have been driven by turbine upscaling (which also continued to bring about in performance improvements), increases in materials prices, energy prices, labor costs, manufacturer profitability, and—in some markets—exchange rate movements [2, 7]. Many of the same factors also resulted in higher costs for other forms of electricity generation equipment (e.g., [8-9]) over a similar timeframe. Figure 3 shows the increase in LCOE from 2004 to 2009.

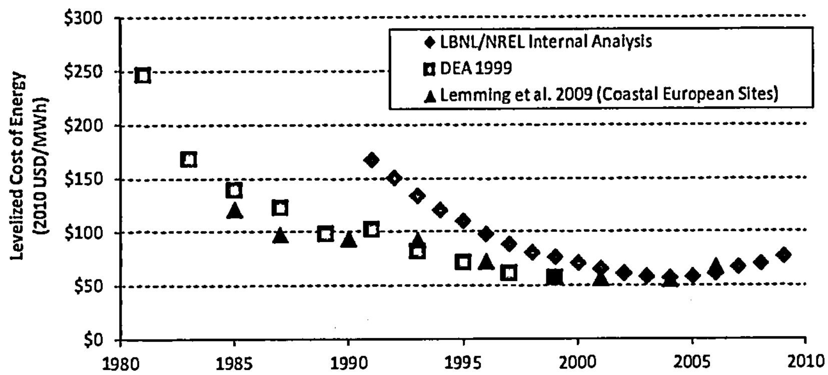
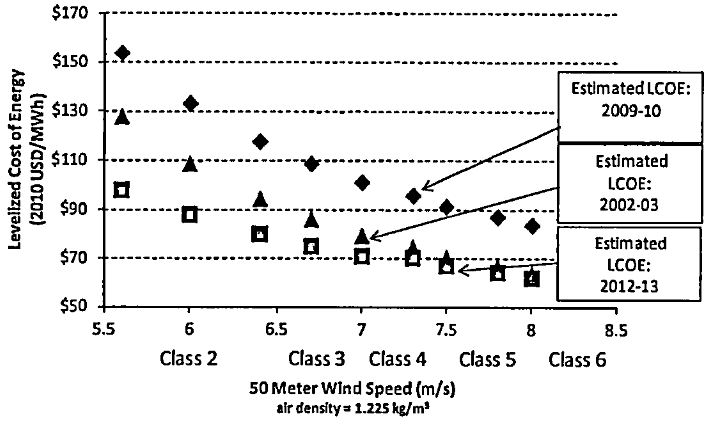


Fig. 3: Estimated LCOE for wind energy between 1980 and 2009 for the United States and Europe (excluding incentives); Sources: LBNL/NREL (internal analysis), [3-4].

3. RECENT AND NEAR-TERM TRENDS IN THE COST OF WIND ENERGY

Since peaking in the late 2000s, project capital costs have declined but still have not returned to their historical lows. At the same time, however, performance improvements have continued. Preliminary analysis conducted by Wiser et al. [10] suggests that projects installed with current state-of-the-art technology in the United States will experience sizable capacity factor improvements within a given wind power class, relative to older technology. Moreover, the most significant performance improvements are occurring in equipment designed for low wind speed sites or those sites that meet IEC Class III wind conditions (typical average hub-height wind speeds of 7.5 m/s). As a result of these technical and design advancements, Wiser et al. [10] find that the amount of U.S. land area that could achieve 35% or higher wind project capacity factors has increased by as much as 270% when comparing today's turbines to those from the 2002–2003 era.

Modeling that applies recent capital cost and performance data from the United States and Denmark for projects expected to be built in 2012–2013 suggests that the LCOE of onshore wind energy is now at an all-time low within fixed wind resource classes and particularly in low and medium wind speed areas where the most significant technology improvements have occurred (Figure 4). This latter fact has significant implications for the amount of land area where projects may be potentially viable. In the United States, for example, the available land area capable of generating wind energy at an unsubsidized LCOE of $62/MWh (2010 U.S. dollars) is estimated to have increased by 42% relative to the land area that could achieve this LCOE using 2002–2003 turbine technology [10].



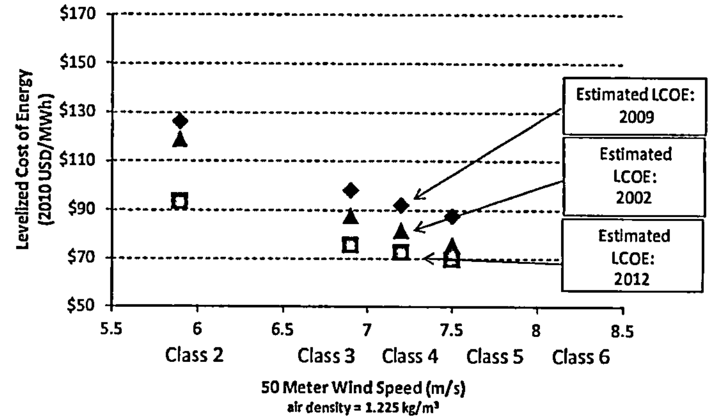


Fig. 4: LCOE for wind energy over time in the United States (left) and Denmark (right) [10-11].

4. LONG-TERM TRENDS IN THE COST OF WIND ENERGY

In the future, several studies suggest that the LCOE of wind energy is likely to continue to fall on a global basis and within fixed wind resource classes. Figure 5 presents the estimated cost reductions anticipated by 13 recent analyses covering 18 cost scenarios. Many of these studies utilize an iterative process involving historical trends and learning curves in combination with expert input, engineering models, and near-term market analysis (e.g., [3, 12-14]).

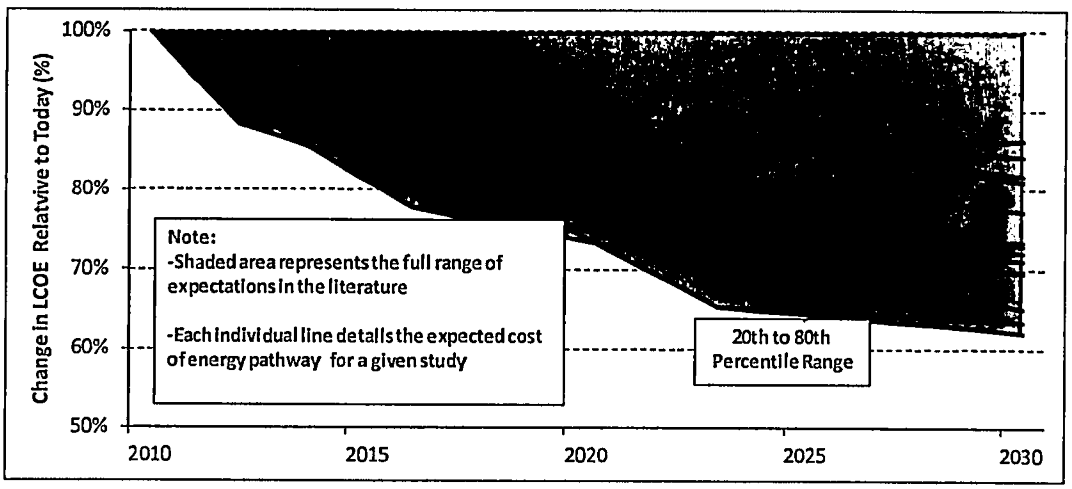


Fig. 5: Estimated range of future wind LCOE across 18 scenarios [3, 13-22] (includes modeling scenarios from multiple other sources).

The data presented in Figure 5 suggest an approximate 0%–40% reduction in LCOE through 2030. By focusing on the results that fall between the 20th and 80th percentiles of scenarios, however, the range is narrowed to roughly a 20%–30% reduction in LCOE. Initial cost reductions range from 1%–6% per year. By 2030, all but one scenario envisions cost reductions falling below 1% per year.

5. DRIVERS OF FUTURE WIND ENERGY COST REDUCTIONS

A large number of technological and market-based drivers are expected to determine whether projections of future costs are ultimately realized. Performance improvements associated with continued turbine upscaling and design advancements are anticipated, and lower capital costs may also be achievable. Possible technical drivers frequently include reduced component loading through a combination of improved materials and enhanced real-time controls capabilities and increased reliability. Reduced component loading is expected to encourage continued cost effective turbine scaling (e.g., growth in both hub heights, rotor diameter, and machine rating), while increased reliability will reduce operations expenditures and minimize turbine downtime. Manufacturing improvements and innovations in logistics challenges are also expected to further reduce the cost of wind energy. Table 1 includes a summary of anticipated sources of future cost reduction as suggested by bottom-up engineering analysis and expert elicitation.

The magnitude of future cost reductions, however, is highly uncertain. Although costs are expected to decline into the future, a resurgence in turbine demand—similar to those observed between 2004 and 2009—could counter these cost reductions. Continued movement toward lower wind speed sites may also invariably increase industry-wide LCOE, despite technological improvements. On the other hand, Asian turbines or increasing competition among manufacturers in general could drive down the LCOE of onshore wind energy to a greater extent than otherwise envisioned.

6. CONCLUSIONS AND FUTURE WORK

Over the past 30 years, the cost of wind energy has significantly decreased, due to both capital cost reductions and performance improvements. However, from roughly 2004 to 2009, continued performance increases were not enough to offset the sizable increase in capital costs of this time period, resulting in an overall increase in the cost of wind energy. Nevertheless, as capital costs have moderated from their 2009–2010 levels, the cost of wind energy has fallen and is now at an all-time low within fixed wind resource classes.

Looking forward, a variety of factors suggest that the LCOE of wind energy will continue to fall on a long-term global basis and within fixed wind resource classes. Most recent estimates project that the LCOE of onshore wind could fall by 20%–30% over the next two decades.

However, other factors may put upward pressure on wind energy costs, such as continued movement towards lower wind speed sites and local factors such as transmission needs. With these factors in mind, it is of utmost importance to consider the interdependence of capital costs and performance and to evaluate the future cost of wind energy on an LCOE basis. Such evaluations must consider trends in the quality of the wind resource in which projects are located, as well as development, transmission, integration, and other cost elements that may also change (and increase) with time and deployment levels.

Further improving our understanding of possible future cost trends will require additional data gathering and improved modeling capability. Robust data collection is needed across the array of variables that must be factored into estimating LCOE and in each of the wind energy markets around the globe. Also needed are data on the many contextual factors that impact the overall cost of wind energy and that may also vary with time, such as interconnection costs, permitting costs, and the average wind speed of installed projects. Such data would allow historical LCOE trends to be more closely analyzed, with insights gleaned both through advanced learning curve analysis as well as bottom-up assessments of historical cost drivers. More advanced component, turbine, and project-level design and cost tools would allow for more sophisticated cost modeling and provide greater insights into possible future costs based on changes in material use and design architectures. Together these efforts would enhance our ability to understand future costs, prioritize R&D efforts, and understand the role and impact of deployment incentives in the future.

TABLE 1: POTENTIAL SOURCES OF THE FUTURE COST OF ENERGY REDUCTIONS IN WIND ENERGY

R&D/Learning Area	Potential Changes (For more detail on technology changes and expected impacts, see references below)	Expected Impact
Drivetrain Technology	Advanced drivetrain designs, reduced loads via improved controls, and condition monitoring [23]	Enhanced drivetrain reliability and reduced drivetrain costs
Manufacturing Efficiency	Higher production volumes, increased automation [24], and onsite production facilities	Enhanced economies of scale, reduced logistics costs, and increased component consistency (allowing tighter design standards and reduced weights)
O&M Strategy	Enhanced condition monitoring technology, design-specific improvements, and improved operations strategies [25]	Real-time condition monitoring of turbine operating characteristics, increased availability, and more efficient O&M planning
Power Electronics/Power Conversion	Enhanced frequency and voltage control, fault ride-through capacity, and broader operative ranges [26]	Improved wind farm power quality and grid service capacity, reduced power electronics costs, and improved turbine reliability
Resource Assessment	Turbine-mounted real-time assessment technology (e.g., LIDAR) linked to advanced controls systems, enhanced array impacts modeling, and turbine siting capacity [26]	Increased energy capture while reducing fatigue loads, allowing for slimmer design margins and reduced component masses; increased plant performance
Rotor Concepts	Larger rotors with reduced turbine loads allowed by advanced controls [27] and application of light-weight advanced materials	Increased energy capture with higher reliability and less rotor mass; reduced costs in other turbine support structures
Tower Concepts	Taller towers facilitated by use of new design architectures and advanced materials [24, 28-29]	Reduced costs to access stronger, less turbulent winds at higher above-ground levels

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KENTUCKY POWER COMPANY

REQUEST

Refer to KPC's response to Sierra Club request no. 24.

a. KPC's response to 24.b indicates that the Company will decide prior to March 12, 2014, whether to opt in to the RPC capacity auction starting in 2017/2018. Please identify KPC's decision and explain the basis for that decision.

b. Referring to SC 1-24 Confidential Attachment 2, explain the basis for, and provide any underlying documents or data to support, the [redacted] identified therein.

RESPONSE

[redacted]

b. [redacted] is an assumed, approximate value that is consistent with past reserve margins in the RPM market. As presented in SC 2-10 Attachment 2, the average Base Residual Auction (BRA) Reserve Margin for the 5 planning years shown was 18.7%. The Fixed Resource Requirement (FRR) reserve margin requirement over the same period was 15.5%.

Further, an estimate of the final effective reserve margin can be computed for some years that includes, in addition to the BRA, the additional impacts of subsequent load forecast adjustments and incremental auctions. For the 3-year historic period shown, that is 24.86%.

WITNESS: Ranie K Wohnhas

Power Coordination Agreement (PCA)
Proposal to the Operating Committee

Date: March 6, 2014
Subject: 2017/2018 PJM FRR / RPM Capacity Election

Background

AEPSC, on behalf of APCo, I&M and KPCo, must advise PJM of elections as to whether these three operating companies will participate in the RPM capacity market or will self-supply their RTO capacity requirements under the FRR alternative for the PJM planning year ("PY") 2017/2018 ("17/18") which runs from June 1, 2017 through May 31, 2018. PJM must be notified of this decision no later than March 12, 2014.

In addition to each operating company's decision to participate in RPM or self-supply under FRR, the PCA allows the option for two or three of the operating companies to enter into a joint FRR plan, whereby these companies are under a combined single, common FRR Plan.

Recommendation

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

TABLE I - REDACTED IN ITS ENTIRETY

RPM Reserve Margins						
PJM Planning Year	**2009/2010**	**2010/2011**	**2011/2012**	**2012/2013**	**2013/2014**	**Average**
Base Residual Auction (BRA) Clearing Reserve Margin	17.80%	16.50%	18.10%	20.90%	20.20%	**18.70%**
Estimated Final Effective PJM RPM Reserve Margin including BRA, subsequent load forecast adjustments and incremental auctions	24.66%	23.66%	26.24%	---*	---*	**24.86%**

*Information was not available in a similar format on the PJM website to perform the calculation for these years.

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 25.a. With regards to the SO_2 and NOx emission reductions at Rockport or increased acquisition of allowances that were "expected to be required . . . to meet its CSAPR allocation levels":

a. Identify the level of reductions of SO_2 and NOx that were expected to be needed to meet the CSAPR allocation levels

b. Identify and produce any analysis, report, or study regarding what was "expected to required" for Rockport to achieve compliance with CSAPR.

RESPONSE

Under the CSAPR, the Rockport Plant would have been allocated emission allowances as shown in Attachment 1 to this response.

a. The level of reductions necessary would have been determined by the availability and price of CSAPR allowances in the market at the time they were needed.

b. I&M, via the NSR Consent Decree, was required to install SO_2 and NOx controls on units 1 and 2 at the Rockport Plant in 2017 and 2019, respectively at the time when the Company was planning for CSAPR compliance. As reflected in the 2011 I&M IRP (IURC Cause No. 44112), prior to those retrofit dates the Company considered fuel-switching options, lower-cost environmental controls, and dispatch optimization options.

WITNESS: Ranie K Wohnhas

Indiana Michigan Power Company - Rockport Plant Emission Allownces Under the Cross State Air Pollution Rule (CSAPR)

	SO2		Annual NOx		Ozone Season NOx	
	2012	2014	2012	2014	2012	2014
Rockport Unit 1	21,292	11,776	7,883	7,788	3,316	3,265
Rockport Unit 2	19,923	11,019	7,376	7,288	3,148	3,100

KENTUCKY POWER COMPANY

REQUEST

Refer to KPC's responses to Sierra Club request nos. 26 and 27. KPC's response to Staff request no. 33 provides an aggregate estimate of environmental compliance costs in 2014, 2015, and 2016. Please provide a detailed breakdown of these cost figures, for each of the units at the Rockport and Mitchell plants, including:

a. The estimated costs specifically attributable to compliance with the Coal Combustion Residuals (CCR) Rule; and

b. The estimated costs specifically attributable to compliance with the Effluent Limitation Guidelines and Standards (ELGs).

c. The estimated costs specifically attributable to compliance with the New Source Review Consent Decree, including the Third Modification, discussed at pages 117 to 119 of the IRP.

RESPONSE

See SC 2-12 Attachment 1 for a detailed breakdown of the costs that were provided in response to Staff 1-33.

Please note that forecasted costs provided in response to Staff 1-33 inadvertently excluded KPCo costs associated with the Rockport Plant. These costs are included in Attachment 1 to this response.

For parts (a) and (b):
Please note that the CCR and ELG Rules are not final at this point in time. The CCR Rule is scheduled to be complete by December 19, 2014. The EPA is currently is currently required to finalize the ELG rulemaking by May 22, 2014.

The Mitchell Plant is currently in the process of a dry fly ash conversion and dry ash landfill construction to meet current permit requirements. However, these projects will also position the Mitchell Plant well for future compliance with the final CCR rulemaking. It is also anticipated that the Mitchell Plant's existing wastewater treatment plant for FGD blowdown, along with the dry flyash conversion and dry ash landfill construction, will position the plant well for compliance with the final ELG rulemaking. Therefore, the costs associated with these projects are related to a great degree, and it is not possible to ascribe a specific cost of compliance with each regulation.

For part (c):
As is also described in the Company's response to Sierra Club 2-13 in this proceeding, some projects that are being performed in 2014, 2015, and 2016 provide for compliance with the Mercury and Air Toxics Standards (MATS) Rule, and cannot be described as solely related to the New Source Review Consent Decree. This includes the Big Sandy 1 refuel (which allows the plant to continue operating beyond the MATS compliance date by ceasing coal-fired operation), as well as the Rockport Dry Sorbent Injection Project (which will meet MATS limits for coal-fired plants) and associated landfill.

WITNESS: John F Torpey

Kentucky Power Company Environmental Compliance Costs by Related Environmental Regulations for 2014 Through 2016

Generating Plant and Unit(s)	Related Environmental Regulations	Year		
		2014	2015	2016
Big Sandy Unit 1*	MATS, NSR Consent Decree	3,541	24,513	23,391
Mitchell Units 1&2*	Current Permit Requirements, CCR, ELG	23,139	4,735	970
Mitchell Units 1&2*	Other Existing Regulations	5,440	3,724	2,818
		32,120	**32,972**	**27,179**

Generating Plant and Unit(s)	Related Environmental Regulations	Year		
		2014	2015	2016
Rockport Units 1&2**	CCR, ELG	-	-	769
Rockport Units 1&2**	MATS, NSR Consent Decree	13,292	4,169	502
Rockport Units 1&2**	NSR Consent Decree, Future CAIR Replacement, NAAQS	203	7,125	12,434
		13,495	**11,294**	**13,705**

Notes:
All costs exclude AFUDC
* - Reflected in Company's response to Staff 1-33
** - Kentucky Power Company Rockport costs reflected as 30% of AEG ownership share of the Rockport Plant

Kentucky Power Company

REQUEST

Identify the estimated costs to KPC specifically attributable to compliance with the New Source Review Consent Decree, including the Third Modification, discussed at pages 117 to 119 of the IRP, for each year of 2017 through 2028.

a. State whether those costs were incorporated into the modeling carried out as part of this IRP.

i. If so, explain how.

ii. If not, explain why not.

RESPONSE

The Company is not able to readily identify the "costs to KPCo specifically attributable to compliance with the New Source Review Consent Decree" as requested. For example: Projects that are included in the Consent Decree are also related to other environmental regulations, such as the Mercury and Air Toxics Standards (MATS Rule). This is true in the case of the retirement of Big Sandy 2, the refuel to natural gas of Big Sandy 1, and the Dry Sorbent Injection project at the Rockport Plant; all of which are also included in the Consent Decree or its subsequent modifications, yet also allow the Company to comply with the MATS Rule.

SCR systems are required to be installed on the two generating units at the Rockport Plant in 2017 and 2019 per the New Source Review Consent Decree. These systems may also allow the units comply with requirements under a Clean Air Interstate Rule replacement, and/or changes to National Ambient Air Quality Standards. The cost of these projects to KPCo is currently estimated to be $18.3 million, $12.5 million, and $11.5 million in 2017, 2018, and 2019 respectively. At this time these costs are estimates and subject to change as engineering, design and construction progress.

Any additional costs associated with future projects or decisions that may affect the operation of generating units are not known with a high degree of certainty at this time. Also, future environmental rules that may change compliance time lines or affect future operations of Kentucky Power's (and I&M's) generating plants are not known at this time, and may impact any costs or decisions that today could be perceived as being associated with the Consent Decree.

For a discussion of the cost of environmental compliance see the Company's response to Staff 1-33 and Sierra Club 2-12.

a. No.

i. N/A

ii. As discussed in the Company's response to Staff 1-33, because all of the portfolios evaluated in Kentucky Power's 2013 IRP included the same existing generation assets there was no need to include any incremental fixed costs for those assets, because the fixed costs for these existing assets would be the same in all portfolios.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to KPC's response to Sierra Club request no. 30.b. Please produce the workpapers, source documents, and underlying data used to generate:

a. the 2017 generic cost estimate, and

b. the annual discount rates for 2017 and subsequent years.

RESPONSE

a/b. Please see response to Sierra Club 2-9c.

WITNESS: John F Torpey

KENTUCKY POWER COMPANY

REQUEST

Refer to KPC's response to Sierra Club request no. 31.

a. Identify and describe in detail the historical relationships that were used to develop each of the correlations shown in Table 21 on page 167 of the IRP.

b. Produce any workpaper, source document, or study used in or developed to establish each of the correlations shown in Table 21 on page 167 of the IRP

c. Confirm whether KPC assumed any correlation between carbon prices and natural gas prices in any of the modeling used in the IRP.

   i. If so, identify the correlation, and produce any workpaper, source document, or study upon which such correlation is based.

   ii. If not, explain why not.

RESPONSE

a. Annual (real) price data from the following sources was used to develop the correlations:

   coal: EIA
   natural gas: EIA
   power prices: EIA
   demand: worldbank

b. Please see Attachment 1 to this response. Because the file contains data that is most useful in electronic format, the Company is providing Attachment 1 on the enclosed CD.

c. Kentucky Power did not assume any correlation between carbon prices and natural gas prices.

   c.(i) N/A

   c.(ii) Sufficiently reliable price data for CO2 does not exist or has not existed long enough.

WITNESS: John F Torpey

KENTUCKY POWER COMPANY

REQUEST

Refer to KPC's response to Staff request no. 18:

a. Please provide a breakdown of the avoided demand/capacity costs the Company modeled, by generation, transmission and distribution.

b. Please explain why the Company assumes zero costs for NOx and SO2 emissions during the IRP planning period.

c. Please explain why the Company assumes no price on carbon until 2022.

RESPONSE

a. See Attachment 1 to this response.

b. There currently is no price on SO2 or NOx emissions, and the Company does not believe costs associated with these effluents are likely to be incurred.

c. For existing sources, EPA was directed to propose guidelines by June 1, 2014, and finalize those standards by June 1, 2015. States would then develop and submit a plan to EPA for implementing the existing source standards by June 30, 2016. The EPA would review and approve or reject the State's implementation plan.

The timing of these EPA or State requirements has not yet been determined. The Company believes that an approximate five year phase-in period is not unreasonable. Note that while the ultimate requirements may not take the form of a price on carbon, carbon price is used as a proxy for whatever requirements are placed on carbon producing sources.

WITNESS: William K Castle

	Generation Capacity $/MW-day	Transmission Capacity $/MW-day	Distribution Capacity $/MW-day
2014	85.05	44.91	0.00
2015	131.83	46.13	0.00
2016	91.30	47.23	0.00
2017	132.49	48.04	0.00
2018	199.74	48.76	0.00
2019	215.54	49.54	0.00
2020	231.74	50.28	0.00
2021	248.55	51.04	0.00
2022	265.99	51.80	0.00
2023	284.08	52.58	0.00
2024	302.83	53.37	0.00
2025	321.95	54.17	0.00
2026	341.74	54.98	0.00
2027	362.23	55.80	0.00
2028	383.42	56.64	0.00
2029	394.85	57.49	0.00
2030	403.15	58.35	0.00
2031	411.61	59.17	0.00
2032	420.26	60.00	0.00
2033	429.08	60.84	0.00
2034	438.09	61.69	0.00
2035	447.29	62.55	0.00

Kentucky Power Company

REQUEST

Refer to KPC's response to Staff request no. 20. Please state whether KPC has considered or evaluated providing an on-bill financing option for customer-distributed solar generation.

RESPONSE

Kentucky Power has not considered or evaluated providing an on-bill financing option for customer-distributed solar generation.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to KPC's response to Staff request no. 22.

a. Please state whether KPC has considered or evaluated opportunities to generate revenue for capacity sales.

b. Referring to KPC's response to 22.b, state whether and when KPC plans to conduct any research regarding "bidding in" energy efficiency and demand response into PJM markets.

c. Referring to KPC's response to 22.d:

   i. Please define the term "sufficient length" as it is used in this response.

   ii. Please provide the "quantity of EE resources" that KPC considers to be "large enough to justify the expense associated with measurement and verification."

RESPONSE

a. No.

b. Kentucky Power will continue to evaluate participation in the PJM capacity market for energy efficiency. No date has been determined for bidding EE into PJM markets.

c. (i) The term "sufficient length" means adequate capacity to meet the PJM installed reserve margin criteria. Refer to the Company's response to Staff 1-31 for an explanation of installed reserve margin and its components.

c. (ii) The quantity is also defendant on the capacity prices in PJM. If prices are higher, lower quantities of energy efficiency resource would, all things being equal, be capable of justifying incremental costs of evaluation as well as risk associated with non-performance.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to KPC's response to Staff request no. 34.

a. Referring to KPC's response to 34.a, state whether KPC has conducted any sensitivity analysis around accelerated cost-effectiveness (i.e., sooner than 2020) for utility scale solar.

   i. If so, provide the results of that analysis
   ii. If not, please explain why no such analysis was performed.

b. Referring to KPC's response to 34.b, please confirm that the "PJM market price"consists of the price of energy and generating capacity in the PJM market.

c. Referring to KPC's response to 34.b, state whether KPC has conducted any sensitivity analysis around cost-effectiveness and market uptake of distributed solar generation.

   i. If so, provide the results of that analysis.
   ii. If not, please explain why no such analysis was performed.

RESPONSE

a. No additional analysis was performed because there is no basis to alter the assumptions used in the Company's analysis, and any result would be hypothetical and would not result in any action on the part of Kentucky Power. Kentucky Power will continue to monitor the cost trajectory of all renewable options as well as the PJM costs.

b. In that context, "market price" was referring to both capacity and energy prices in the PJM market.

c. Kentucky Power has not performed that analysis.

i. N/A

ii. There is not sufficient information available given the low retail rates, low insulation, and prevalence of low income customers that is quite different from markets like California, New Jersey, and Hawaii where solar is currently achieving higher penetrations.

WITNESS: John F Torpey

Kentucky Power Company

REQUEST

Refer to KPC's response to Staff request no. 46. With regards to valuing solar, please explain in detail the manner by which "[a]dditional value that might accrue from the transmission and distribution system was discounted due to the winter peaking nature of the T&D systems." Please quantify the discount.

RESPONSE

Kentucky Power has not quantified the value that might accrue from the T&D systems.

WITNESS: William K Castle

KENTUCKY POWER COMPANY

REQUEST

a. Explain how the Plexos® Linear Program evaluates solar resources. In providing this explanation, please include:

b. the unit incremental size considered and why that unit size was considered; all inflation adjustments and their cause; and any and all assumptions about costs (including overnight capital costs, variable and fixed operating costs, and other costs and credits), unit expected life, and other cost-related and performance factors, for the longer of each year of the IRP or the expected life of solar resources.

RESPONSE

a. The utility solar assumed a 15 MW block and the distributed solar assumed a .667 MW block.

b. Please see Attachment 1 to this response.

WITNESS: John F Torpey

Solar PPA - Levelized Price 30 yrs

	Forecast Installed Cost $/W	PV Capacity Credit $/W	ITC $/W	Net Installed Cost $/W	Energy Only Levelized Cost $/MWh - 8%	Energy & Capacity Levelized Cost $/MWh - 8%
2014	2.83	0.46	0.85	1.51	104.19	136.19
2015	2.57	0.50	0.77	1.30	89.41	123.94
2016	2.34	0.53	0.70	1.11	76.13	112.78
2017	2.13	0.45	0.21	1.47	101.17	131.95
2018	1.94	0.47	0.19	1.27	87.49	120.08
2019	1.70	0.50	0.17	1.03	70.96	105.06
2020	1.50	0.52	0.15	0.83	57.34	92.95
2021	1.50	0.54	0.15	0.81	55.85	92.95
2022	1.50	0.56	0.15	0.79	54.38	92.95
2023	1.50	0.58	0.15	0.77	52.94	92.95
2024	1.50	0.60	0.15	0.75	51.55	92.95
2025	1.50	0.62	0.15	0.73	50.22	92.95
2026	1.50	0.64	0.15	0.71	48.95	92.95
2027	1.50	0.66	0.15	0.69	47.76	92.95
2028	1.50	0.67	0.15	0.68	46.66	92.95
2029	1.50	0.69	0.15	0.66	45.68	92.95
2030	1.50	0.70	0.15	0.65	44.72	92.95

Kentucky Power Company

REQUEST

Describe how the IRP and the Plexos® Linear Program account for locational differences in value, changes in installation cost, changes in capacity factors and capacity value (such as Effective Load Carrying Capability), and changes in other site-specific values associated with increased numbers of solar installations.

RESPONSE

For this IRP, locational differences were not evaluated. Changes in cost are described in Section 4.3.4.5 of the 2013 IRP Report. Capacity factors and effective capacity values were unchanged.

WITNESS: John F Torpey

KENTUCKY POWER COMPANY

REQUEST

Refer to "Table 2: Peak Internal Demand and Energy Requirements Including Approved E" on page 8, and to the discussion on pages 37-38 of the IRP (Volume A).

a. Explain what factors result in an expected summer peak internal demand growth rate that is three times greater than overall internal demand growth rate.

b. Describe in detail the factors and relative weights used in determining the "Xcool" variable.

RESPONSE

a. Please refer to Exhibit 2-3 for the average annual growth rates over the 2014-2028 forecast horizon. The difference between the summer peak demand forecast and the annual energy requirements forecast is 0.1 percent per year over the forecast period. Furthermore, the forecasts on Exhibit 2-9 (forecasts before EE impacts), indicate there is no difference between the average annual growth rates for energy requirements and summer peak demand; i.e., both grow at 0.3 percent per year over the forecast horizon. Thus, in essence, there is no material difference in the projected growth between the two forecasts.

b. See Attachment 1 to this response for Itron's description of the residential model including the factors used to develop the XCOOL variable.

WITNESS: William K Castle

Appendix A: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, the strength of econometric models is that they are well suited to identifying historical trends and to projecting these trends into the future. In contrast, the strength of the end-use modeling approach is the ability to identify the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2012 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \qquad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \middle/ Eff_{05}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2005 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{05} \times SurfaceArea_{05}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2005 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times HeatShare_{05}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2005 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	505
Electric Space Heating Heat Pump	190

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2011 Version of the SAE models, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a ten year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10 year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m} \right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m} \right)^{\gamma} \quad (8)$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtHDD_{y,m}}{HDD_{05}}\right) \times \left(\frac{HHSize_{y}}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_{y}}{Income_{05}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05,7}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05,7}}\right)^{\kappa} \qquad (9)$$

Where:

- *BDays* is the number of billing days in year (*y*) and month (*m*), these values are normalized by 30.5 which is the average number of billing days
- *WgtHDD* is the weighted number of heating degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2005
- *HHSize* is average household size in a year (*y*)
- *Income* is average real income per household in year (*y*)
- *ElecPrice* is the average real price of electricity in month (*m*) and year (*y*)
- *GasPrice* is the average real price of natural gas in month (*m*) and year (*y*)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes

- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \big/ Eff_{05}^{Type} \right)} \tag{11}$$

Data values in 2005 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2005. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2005 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{05}^{Type}}{HH_{05}} \times CoolShare_{05}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2005 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,661
Space Cooling Heat Pump	369
Room Air Conditioning	315

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2012 SAE models, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities. Formally,

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{05}^{Type} \Big/ Eff_{05}^{Type} \right)} \times \left(TenYearMovingAverageElectricPrice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGasPrice_{y,m}\right)^{\gamma} \quad (13)$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{WgtCDD_{y,m}}{CDD_{05}}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.20} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{05}}\right)^{\lambda} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{05}}\right)^{\kappa} \tag{14}$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2005.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2005). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

The first term on the right hand side of this expression (*OtherEqpIndex*$_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term

(*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_{y}^{Type} \Big/ \frac{1}{UEC_{y}^{Type}} \right)}{\left(Sat_{05}^{Type} \Big/ \frac{1}{UEC_{05}^{Type}} \right)} \times MoMult_{m}^{Type} \times \qquad (16)$$

$$(TenYearMovingAverageElectric\Pr ice)^{\lambda} \times (TenYearMovingAverageGas\Pr ice)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.5}\right) \times \left(\frac{HHSize_y}{HHSize_{05}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{05}}\right)^{0.10} \times$$

$$\left(\frac{Elec\Pr ice_{y,m}}{Elec\Pr ice_{05}}\right)^{\phi} \times \left(\frac{Gas\Pr ice_{y,m}}{Gas\Pr ice_{05}}\right)^{\lambda} \qquad (17)$$

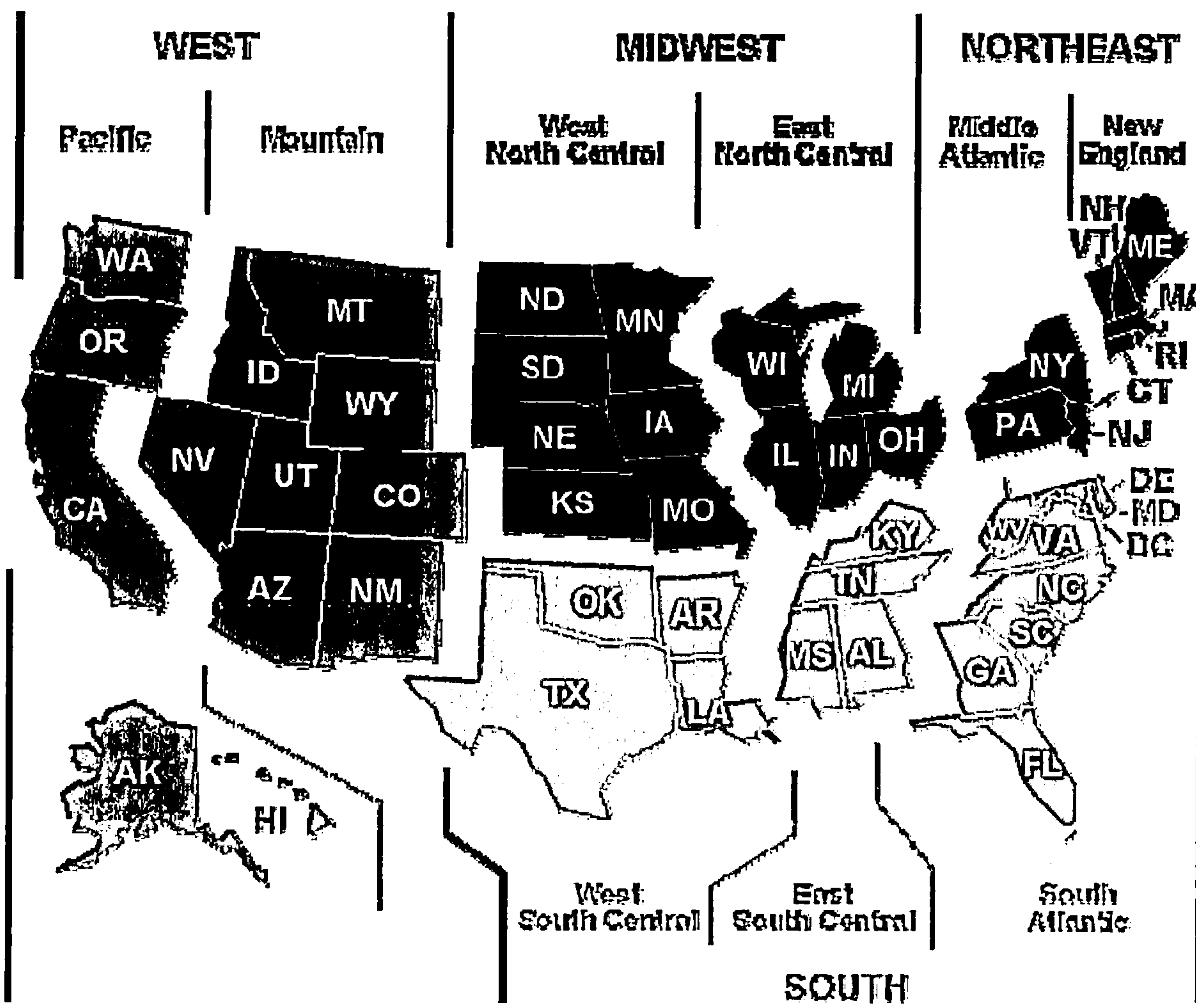
The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \quad (18)$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 26. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3.

Figure 26: Mapping of States to Census Divisions



Source: http://www.eia.doe.gov/emeu/reps/maps/us_census.html

Table 3: List of SAE Files

Spreadsheet	*MetrixND* Project File
NewEngland.xls	SAE_NewEngland.ndm
MiddleAtlantic.xls	SAE_MiddleAtlantic.ndm
EastNorthCentral.xls	SAE_EastNorthCentral.ndm
WestNorthCentral.xls	SAE_WestNorthCentral.ndm
SouthAtlantic.xls	SAE_SouthAltantic.ndm
EastSouthCentral.xls	SAE_EastSouthCentral.ndm
WestSouthCentral.xls	SAE_WestSouthCentral.ndm
Mountain.xls	SAE_Mountain.ndm
Pacific.xls	SAE_Pacific.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The *MetrixND* project files are linked to the data in these spreadsheets. In these project files, the end-use *Usage* variables are constructed and the SAE model is estimated.

Each of the nine SAE spreadsheets contains the following tabs.

- **Definitions.** Contains equipment, end use, worksheet, and Census Division definitions.
- **AnnualIndices.** Contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **ShareUEC.** Calculates the annual equipment indices.
- **Shares.** Contains historical and forecasted equipment shares. The default forecasted values are provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **Efficiencies.** Contains historical and forecasted equipment efficiency trends. The forecasted values are based on projections provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **StructuralVars.** Contains historical and forecasted square footage, number of households, building shell efficiency index, and calculation of structural variable. The forecasted values are based on projections provided by the EIA.
- **EIAData.** Contains the raw forecasted data provided by the EIA. This tab also contains calculations of the base year *Intensity* values used to weight the equipment indices.
- **MonthlyMults.** Contains monthly multipliers that are used to spread the annual equipment indices across the months.
- **EV.** Worksheet for incorporating electric vehicle (EV) impacts.
- **PV.** Worksheet for incorporating photovoltaic battery (PV) impacts.

The *MetrixND* Project files are linked to the *AnnualIndices*, *ShareUEC*, and *MonthlyMults* tabs in the spreadsheets. Sales, economic, price and weather information for the Census Division is provided in the linkless data table *UtilityData*. In this way, utility specific data and the equipment indices are brought into the project file. The *MetrixND* project files contain the objects described below.

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use. There are five types of elasticities included on this table.

  - Economic variable elasticities
  - Short-term own price elasticities
  - Short-term cross price elasticities
  - Long-term own price elasticities
  - Long-term cross price elasticities

  The short-term price elasticities drive the end-use usage equations. The long-term price elasticities drive the Heat, Cool and other appliance indices. The combined price impact is an aggregation of the short and long-term price elasticities. As such, the long-term price elasticities are input as incremental price impact. That is, the long-term price elasticity is the difference between the overall price impact and the short-term price elasticity.

Data Tables

- **AnnualEquipmentIndices.** This data table is linked to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData.** This is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults.** This data table is linked to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **ResidentialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.

- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table is used to compute the monthly sales forecasts by end uses.

Models

- **ResModel:** This is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are included in this package contain regional data. If you have more accurate data for your service territory, you are encouraged to tailor the spreadsheets with that information. This section describes the steps needed to customize the files.

Minimum Customization

- Save the *MetrixND* project file and the spreadsheet into the same folder
- Select the spreadsheet and *MetrixND* project file from the appropriate Census Division
- Open the spreadsheet and navigate to the *EIAData* tab
- In cell "AV27", replace base year Census Division use per customer with observed use per customer for your service territory
- Save the spreadsheet and open the *MetrixND* project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Customizing the End-use Share Paths

In addition to the minimum steps listed above, you can install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region.

Customizing the End-use Efficiency Paths

Finally, you can override the end-use efficiency paths that are contained on the *Efficiencies* tab of the spreadsheet.

Kentucky Power Company

REQUEST

Refer to "Table 4: Kentucky Power Existing DSM Programs" on page 12 of the I.R.P. (Volume A).

a. State whether KPC has ever evaluated distributed solar electric generation for inclusion as a demand side management resource.

   i. If so, please describe what the process of evaluation was, and provide the results of that evaluation.

   ii. If not, please explain why KPC has never done such an evaluation.

RESPONSE

a. Yes.

(i) In this I.R.P., Kentucky Power evaluated distributed generation in the form of solar electric generation. Given current net metering provisions, Kentucky Power determined that distributed solar increases revenue requirements. See section 4.7.1 of the I.R.P. Report for further discussion.

(ii) N/A

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to "Table 7: Financial Effects" on page 17 of the IRP (Volume A).

a. List and explain all factors included in developing this table.

b. Identify any factors that were considered, but excluded, when developing this table.

c. Referring to the note to Table 7, please explain in detail what "transmission and distribution-related" and "base generation-related" cost increases were not considered in the IRP.

d. State whether the rates reflected in Table 7 include the impact of the requirement in the New Source Review Consent Decree to install Selective Catalytic Reduction controls on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively, as discussed on page 118 of the IRP.

   i. If so, identify the impact of the SCR installations on rates starting in 2018 and 2020, respectively.

   ii. If not, explain why not.

e. State whether the rates reflected in Table 7 include the impact of the requirement in the Third Modification of the New Source Review Consent Decree to install "high efficiency scrubbers" on Rockport Units 1 and 2 by December 31, 2025 and December 31, 2028, respectively.

   i. If so, identify the impact of the scrubber installations on such rates

   ii. If not, explain why not.

RESPONSE

a. The table was developed by starting with the present value of the cost of the preferred plan in 2014, divided by the 2014 energy requirements, then adding, for each subsequent year, the annual incremental cost of the preferred plan divided by the Company's energy requirements for that incremental year. The costs considered are the generation related variable cost and incremental generation or demand side fixed cost that were used to evaluate the resource portfolios.

b. Costs that do not differ among plans being evaluated are excluded from this table. For example, costs (except variable costs) associated with the ongoing operation of the Mitchell and Rockport plants are excluded from this table.

c. Transmission and distribution related costs refer to any costs, expected to be incurred by Kentucky Power that would not differ between the resource plans being evaluated. For example, ongoing maintenance cost of the transmission and distribution system were not included, as these costs would not differ among the plans being evaluated, however, Volt VAR Optimization costs would be included. Base generation-related costs include ongoing costs to operate and maintain Rockport and Mitchell, with the exception that variable costs associated with those plants would be included.

d. (i) and e.(i) No.

d. (ii) and e.(ii) All portfolios that were evaluated included the continued operation of Rockport, so any incremental fixed or capital investment costs associated with Rockport would not be a factor in selecting the better portfolio.

WITNESS: John F Torpey

KENTUCKY POWER COMPANY

REQUEST

Refer to section 2.3.3.7.b on page 41 of the IRP (Volume A). Please detail the components of "lost and unaccounted for energy" and relative weights and respective drivers of those components for all years in the IRP.

RESPONSE

Losses and unaccounted for energy represents the difference between total load for the area (net generation plus imports less exports) and billed and accrued energy sales to retail and internal wholesale customers. Losses and unaccounted for energy (losses) are modeled using Company loss study results. They are applied to each revenue class. Loss study results are translated from voltage level losses to revenue class loss percentage. The class sales forecast and loss study determine the losses forecast. Please see Attachment 1 for the annual losses by revenue class.

WITNESS: William K Castle

Kentucky Power - GWh Lost and Unaccounted for Energy Forecast

Annual

Year	Residential GWh	Residential Loss Factor	Commercial GWh	Commercial Loss Factor	Industrial GWh	Industrial Loss Factor	Other Ultimate GWh	Other Ultimate Loss Factor	Total Ultimate GWh	Total Ultimate Loss Factor	FERC Municipals GWh	FERC Municipals Loss Factor	Total GWh	Total Loss Factor
2014	201	8.2%	105	7.2%	100	3.4%	1	7.9%	407	5.9%	3	2.6%	410	5.9%
2015	200	8.2%	106	7.2%	101	3.4%	1	7.9%	407	5.9%	3	2.6%	410	5.9%
2016	199	8.1%	105	7.2%	101	3.4%	1	7.9%	407	5.9%	3	2.6%	409	5.9%
2017	196	8.1%	105	7.1%	101	3.4%	1	7.9%	402	5.8%	3	2.6%	405	5.8%
2018	197	8.1%	105	7.2%	101	3.4%	1	7.9%	405	5.9%	3	2.6%	407	5.8%
2019	196	8.1%	106	7.2%	101	3.4%	1	7.9%	404	5.9%	3	2.6%	407	5.8%
2020	197	8.1%	107	7.2%	102	3.4%	1	7.9%	407	5.9%	3	2.6%	410	5.9%
2021	195	8.1%	106	7.2%	102	3.4%	1	7.9%	403	5.8%	3	2.6%	406	5.8%
2022	196	8.1%	107	7.2%	103	3.4%	1	7.9%	406	5.9%	3	2.6%	409	5.8%
2023	196	8.1%	108	7.2%	103	3.4%	1	7.9%	408	5.9%	3	2.6%	411	5.8%
2024	196	8.1%	108	7.2%	103	3.4%	1	7.9%	408	5.9%	3	2.6%	411	5.8%
2025	195	8.0%	109	7.2%	103	3.4%	1	7.9%	407	5.8%	3	2.6%	410	5.8%
2026	195	8.1%	109	7.2%	103	3.4%	1	7.9%	409	5.8%	3	2.6%	412	5.8%
2027	197	8.1%	111	7.2%	104	3.4%	1	7.9%	412	5.9%	3	2.6%	415	5.8%
2028	196	8.1%	111	7.2%	104	3.4%	1	7.9%	413	5.9%	3	2.6%	416	5.8%

Summer

Year	Residential GWh	Residential Loss Factor	Commercial GWh	Commercial Loss Factor	Industrial GWh	Industrial Loss Factor	Other Ultimate GWh	Other Ultimate Loss Factor	Total Ultimate GWh	Total Ultimate Loss Factor	FERC Municipals GWh	FERC Municipals Loss Factor	Total GWh	Total Loss Factor
2014	83	8.1%	66	9.1%	61	4.2%	1	14.3%	211	6.6%	0	0.4%	211	6.5%
2015	76	7.5%	64	8.7%	59	4.1%	1	14.1%	200	6.2%	0	0.5%	200	6.1%
2016	80	8.0%	63	8.6%	56	3.9%	1	13.8%	201	6.3%	0	0.4%	201	6.2%
2017	80	8.0%	64	8.6%	59	4.0%	1	13.9%	204	6.3%	0	0.7%	205	6.3%
2018	80	8.0%	64	8.6%	59	4.0%	1	13.9%	204	6.3%	0	0.7%	205	6.3%
2019	81	8.0%	65	8.7%	60	4.1%	1	13.9%	207	6.4%	0	0.7%	207	6.3%
2020	80	8.0%	64	8.6%	56	3.8%	1	13.7%	201	6.2%	0	0.4%	201	6.1%
2021	81	8.0%	65	8.7%	60	4.0%	1	13.8%	206	6.3%	0	0.6%	206	6.3%
2022	80	8.0%	65	8.7%	60	4.0%	1	13.8%	206	6.3%	0	0.6%	207	6.2%
2023	81	8.0%	66	8.6%	60	4.0%	1	13.8%	207	6.3%	0	0.6%	207	6.2%
2024	81	8.0%	66	8.6%	57	3.8%	1	13.6%	204	6.2%	0	0.3%	204	6.1%
2025	82	8.1%	67	8.7%	60	4.0%	1	13.8%	210	6.4%	0	0.6%	211	6.3%
2026	82	8.1%	68	8.8%	60	4.0%	1	13.8%	211	6.4%	0	0.6%	211	6.3%
2027	82	8.1%	68	8.7%	60	4.0%	1	13.7%	211	6.4%	0	0.6%	211	6.3%
2028	81	8.0%	67	8.6%	56	3.7%	1	13.5%	205	6.2%	0	0.3%	206	6.1%

Winter

Year	Residential GWh	Residential Loss Factor	Commercial GWh	Commercial Loss Factor	Industrial GWh	Industrial Loss Factor	Other Ultimate GWh	Other Ultimate Loss Factor	Total Ultimate GWh	Total Ultimate Loss Factor	FERC Municipals GWh	FERC Municipals Loss Factor	Total GWh	Total Loss Factor
2014	116	8.1%	39	5.4%	40	2.7%	0	2.5%	195	5.3%	2	4.6%	197	5.3%
2015	118	8.2%	46	6.4%	47	3.1%	0	3.0%	211	5.8%	2	4.5%	214	5.8%
2016	115	8.0%	41	5.7%	39	2.6%	0	2.6%	195	5.3%	2	4.1%	197	5.3%
2017	117	8.2%	41	5.7%	41	2.7%	0	2.7%	199	5.5%	2	4.2%	202	5.4%
2018	116	8.1%	42	5.8%	41	2.8%	0	2.7%	200	5.5%	2	4.2%	202	5.4%
2019	119	8.4%	45	6.2%	49	3.2%	0	3.0%	213	5.8%	3	4.6%	216	5.8%
2020	115	8.1%	43	5.9%	39	2.6%	0	2.7%	197	5.4%	2	4.3%	199	5.4%
2021	115	8.1%	44	6.0%	43	2.8%	0	2.8%	202	5.5%	2	4.3%	204	5.5%
2022	115	8.1%	45	6.2%	43	2.8%	0	2.8%	204	5.5%	2	4.3%	206	5.5%
2023	118	8.3%	48	6.5%	49	3.2%	0	3.1%	215	5.8%	3	4.6%	218	5.8%
2024	111	7.9%	45	6.1%	40	2.6%	0	2.6%	196	5.3%	2	4.2%	198	5.3%
2025	114	8.1%	46	6.1%	43	2.8%	0	2.8%	202	5.5%	2	4.3%	205	5.5%
2026	116	8.2%	47	6.2%	44	2.8%	0	2.9%	207	5.6%	3	4.4%	209	5.6%
2027	116	8.2%	51	6.6%	52	3.3%	0	3.2%	219	5.9%	3	4.7%	222	5.8%
2028	110	7.8%	46	6.0%	42	2.7%	0	2.7%	198	5.3%	2	4.2%	201	5.3%

Kentucky Power Company

REQUEST

Refer to Exhibit 2-5 on page 59 of the IRP (Volume A). Please provide a detailed breakout of the total losses by components of total loss, by assignment to customer class, and by winter and summer.

RESPONSE

Exhibit 2-5 on page 59 of the IRP is 2014 monthly load including energy efficiency (EE) impacts. Please see Attachment 1 to this response for 2014 monthly loss factors by revenue class and aggregated summer and winter values.

WITNESS: William K Castle

Kentucky Power Company
Monthly Losses and Unaccounted for Energy in GWh

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	Summer	Winter
Residential	16	17	-1	19	14	24	6	15	5	14	43	29	201	83	119
Commercial	11	13	7	10	7	12	12	16	9	-8	7	9	105	66	38
Industrial	27	15	10	9	-2	4	13	13	24	-12	-8	8	100	61	39
Other Ultimate	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0
Total Ultimate	54	45	16	38	20	41	31	44	38	-6	42	46	407	211	197
Sales-for-Resale	0	0	1	0	0	0	0	0	0	0	0	1	3	0	2
Total Losses	54	45	17	38	20	41	30	44	38	-6	42	47	410	211	199

KPSC Case No. 2013-00475
Sierra Club's Second Set of Data Requests
Date March 7, 2014
Item No. 27
Attachment 1

Kentucky Power Company

REQUEST

Refer to Section 3.5.1.5 on page 93 of the IRP (Volume A).

a. Please explain how distributed generation technologies "result in a reduction to load and additional incremental costs to the utility to accommodate." (emphasis in original). Please quantify the "reduction to load" and "additional incremental costs."

b. Regarding the factors evaluated in assessing the "resource value" of distributed solar:

  i. Please identify which factors were evaluated.
  ii. Please explain how these factors were evaluated.
  iii. Please describe the assumptions that were used in, and the results of, these evaluations.

RESPONSE

a. When "behind-the-meter" generation is installed, the load on the utility side of the meter will be less. The amount of the reduction to load will depend upon the type and size of behind-the-meter generation installed. Additional costs are the net metering credits generated by the resource as well as any utility costs associated with the hook-up, metering, and billing of that resource.

b. (i) Kentucky Power evaluates the following factors as part of its evaluation of the resource value of distributed solar: the load shape of a solar resource in Kentucky, degradation of the solar output over time, the life of the solar panel, a line loss factor, capacity prices in PJM, and energy prices in PJM.

b. (ii) The solar load shape is a series of energy and capacity impacts that repeats for the life of the panel. The output is slightly less each successive year due to degradation. The output of the panel is grossed-up by the amount of line losses it avoids. The energy and capacity impacts are assigned their PJM value for the life of the panel and discounted back to present value.

b. (iii) Solar resources were evaluated using a solar shape from an actual solar resource located in Ohio. Degradation was assumed to be 0.5% annually. Line losses were assumed to be 8%. Please see Figure 22 of the Kentucky Power IRP for the resultant resource value of distributed solar.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 3.5.1.6 on page 93 of the IRP (Volume A). Please confirm that of the distributed generation ("DG") technologies, only solar DG was evaluated as a resource. If this not confirmed, please state what DG alternatives were evaluated, describe any such evaluation and quantify any cost estimates derived.

RESPONSE

Confirmed.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 99 of the IRP (Volume A). Explain how KPC reconciled costs borne by distributed solar generation customers operating net metering generation in comparing the value of these resources to PJM resources.

RESPONSE

Kentucky Power did not consider costs borne by customers for customer-sited generation within the optimizations. Only the compensation (net metering credits) and the PJM value (capacity and energy) were considered. However, customer costs and customer compensation (net metering credits) were considered when the economics of distributed solar resources were evaluated from the perspective of the customer.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to "Table 12: EE Resource Costs" on page 108 of the IRP (Volume A).

a. Please identify what resources are included within the "All Other" category in Table 12.

b. Please describe the relative contribution of each of the resources included in the "All Other" category.

RESPONSE

a. & b. The resource categories and their relative contribution (on a MWh basis) are included in Attachment 1 to this response.

WITNESS: William K Castle

Commercial - All Other

Cooking and Laundry	1.0%
Design Assistance	3.2%
Other Efficiency	8.2%
Other Fuel Switch	0.1%
Other Indirect Activity	20.1%
Space Heat Efficiency	1.4%
Space Heat Fuel Switch	5.1%
Ventilation	60.9%
All Other	100.0%

Residential - All Other

Hot Water Efficiency	8.7%
Hot Water Fuel Switch	12.5%
Monitoring & Metering	37.1%
Motors	0.7%
Other Fuel Switch	2.1%
Other Indirect Activity	34.4%
Space Heat Fuel Switch	0.4%
Ventilation	4.1%
All Other	100.0%

Kentucky Power Company

REQUEST

Refer to "Table 13: DSM Program Costs Estimate" on page 108 of the IRP (Volume A).

a. Please describe KPC's assumptions about the value to KPC and its ratepayers of distributed solar.

b. Please describe the net cost calculation for distributed solar used by KPC.

c. Please describe which impacts KPC considered from distributed solar generation beyond the impact of the net metering credit on revenue requirements.

d. Please describe what components of the revenue impact of the net metering credit are avoided by KPC and/or its ratepayers as a result of customer-owned distributed solar generation.

RESPONSE

a. Kentucky Power assumed that net metering credits would continue at the full retail rate for the planning period. The retail rate was further assumed to escalate at 2% annually. Distributed solar avoids capacity and energy at the PJM rate. The net metering credit was not considered a "transfer payment" when evaluating revenue requirements. The net impact results in an increased revenue requirement for remaining ratepayers.

b. Table 13 incorrectly describes the "Distributed Solar (Net Metering)" as a program cost. In fact, these are the present value of net metering payments associated with net metering additions.

c. Net metered solar had costs associated with net metering payments only.

d. Ratepayer revenue requirement increases by the amount of the net metering credit, less the cost of the avoided energy and capacity (PJM value).

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 4.3.5.2 on page 138 of the IRP (Volume A). Regarding the optimization of other demand-side resources, including solar generation, please describe what benefits or value to KPC or its ratepayers were modeled.

RESPONSE

Demand-side resources, including distributed solar, were modeled as resources which provide capacity and energy benefits to the system, as a whole.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 139 of the IRP (Volume A). Describe how avoided transmission costs, including capital, operating, maintenance, and outage costs, were incorporated into the evaluation of distributed solar generation. Please describe the results of that evaluation.

RESPONSE

As described in section 4.7.1, transmission costs were not included in the evaluation of distributed generation because of the winter-peaking nature of Kentucky Power. Kentucky Power does not have sufficient data to incorporate incremental operational, maintenance, or outage costs or cost savings that may result from distributed solar installations.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 148 of the IRP (Volume A). Describe how avoided fuel costs and fuel adequacy and procurement costs were incorporated into the evaluation of distributed solar generation. Please describe the results of that evaluation.

RESPONSE

Distributed solar was evaluated relative to avoided PJM costs which implicitly include fuel adequacy and procurement costs. The results of that evaluation are discussed in section 4.7.1 of the IRP.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to page 161 of the IRP (Volume A).

a. Please confirm that PJM avoided cost is the maximum value assigned to distributed solar resources.

b. Please describe in detail how the PJM avoided cost is calculated for use in the IRP, and the expected values over the life of a solar plant or the IRP, whichever is longer.

RESPONSE

a. The value assigned to distribute solar was the PJM value (forecast).

b. The Fundamentals Analysis Group developed the long-term PJM energy market forecast which represents the PJM avoided cost for use in the IRP. The long-term pricing forecasts used in this analysis include: natural gas prices, CO_2 mitigation values, regional coal prices, on and off-peak energy prices and capacity values within the PJM RTO. The primary tool the Fundamentals Analysis Group uses for developing its long-term, energy-related commodity pricing forecasts is the AuroraXMP model. The AuroraXMP model iteratively generates locational, but not company-specific, long-term capacity expansion plans, annual energy dispatch, fuel burns and emission totals from inputs including fuel, load, emissions and capital costs, among others.

WITNESS: William K Castle

KENTUCKY POWER COMPANY

REQUEST

Refer to page 162 of the IRP (Volume A). Provide data and analysis to support the statement that "[t]here is limited utility evidence to support that claim [that distributed solar generation offsets other grid investments]."

RESPONSE

The excerpt included in the data request unfairly truncates the relevant discussion in the IRP. In full, the Company stated:

"However, there is limited utility evidence to support that claim that given the winter peaking nature of Kentucky Power. There is virtually no solar production at the hour of Kentucky Power's (winter) peak (typically a winter weekday morning) which nullifies that argument for Kentucky Power as shown in Figure 23."

Stated otherwise, because the amount of solar production at the likely times of the Company's winter peak falls far short of the Company's peak winter demand, the Company will be unable to rely upon distributed solar generation to offset the need for other grid investments.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to "Figure 23: Solar Production vs. Demand of Kentucky Power" on page 163 of the IRP (Volume A). Please provide the Company's analysis of effective load carrying capability for solar production in the KPC service territory.

RESPONSE

Due to the immaturity and size of the distributed solar capability in the Kentucky Power service territory, no such studies have been performed.

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to "Figure 24: Preferred Portfolio Distributed Solar Adoption Assumption" on page 164 of the IRP (Volume A). Please produce any workpapers, source documents, and, in machine readable format with formulas intact, input and output files, used in or developed as part of the analysis reflected in this Figure.

RESPONSE

Please see Attachment 1 to this response.

WITNESS: William K Castle

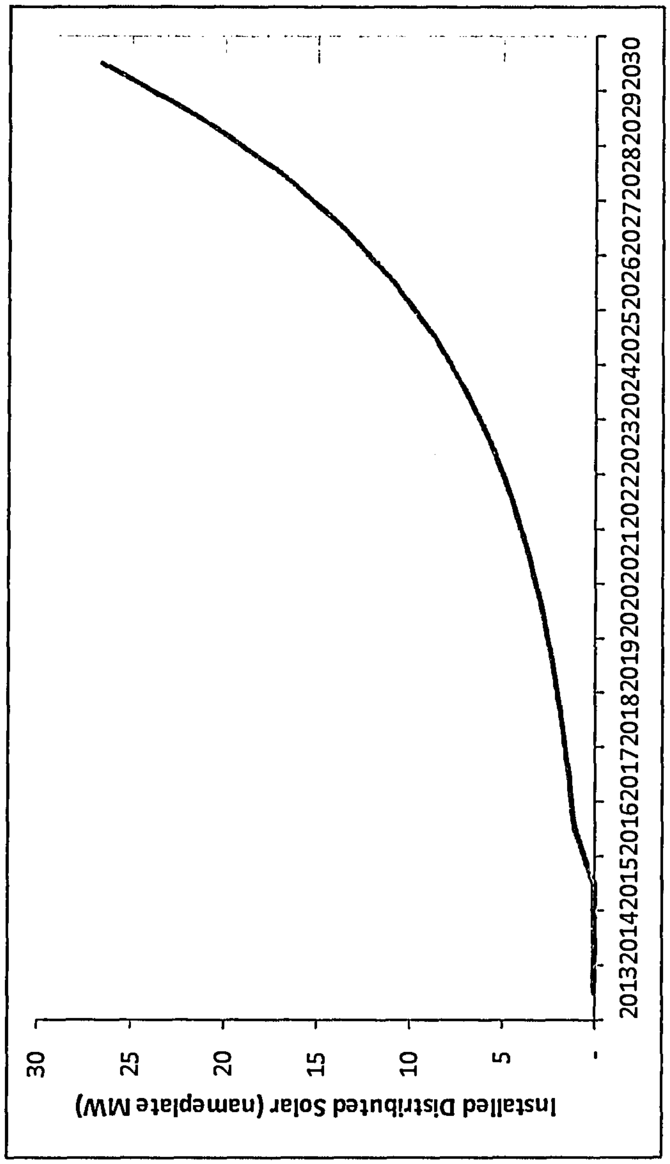
Growth Rates	
thru 2016	40%
2017-2018	30%
2019+	25%
Line Loss	8%

Cumulative

	Nameplate MW	Energy at Gen (MWh)
2013	0.03	44
2014	0.04	62
2015	0.06	86
2016	1.08	1,588
2017	1.41	2,065
2018	1.83	2,684
2019	2.29	3,355
2020	2.86	4,194
2021	3.57	5,242
2022	4.47	6,553
2023	5.58	8,191
2024	6.98	10,239
2025	8.72	12,798
2026	10.90	15,998
2027	13.63	19,998
2028	17.04	24,997
2029	21.29	31,246
2030	26.62	39,058

Incremental

	Nameplate MW	Energy at Gen (MWh)	blocks /year	20
2013	0.03	44	2	
2014	0.01	18	1	
2015	0.02	25	1	
2016	1.02	1,502	75	
2017	0.32	476	24	
2018	0.42	619	31	
2019	0.46	671	34	
2020	0.57	839	42	
2021	0.71	1,048	52	
2022	0.89	1,311	66	
2023	1.12	1,638	82	
2024	1.40	2,048	102	
2025	1.74	2,560	128	
2026	2.18	3,200	160	
2027	2.73	4,000	200	
2028	3.41	4,999	250	
2029	4.26	6,249	312	
2030	5.32	7,812	391	


Installed Distributed Solar (nameplate MW)
30
25
20
15
10
5
-
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

Kentucky Power Company

REQUEST

Refer to page 164 of the IRP (Volume A).

a. State whether data from Vermont was used in development of the IRP with respect to solar resources.

b. If so:

   i. Explain how such data was used
   ii. Produce this Vermont data that was used.
   iii. Explain why KPC decided to use this Vermont data.

RESPONSE

a. No.

b. N/A

WITNESS: William K Castle

Kentucky Power Company

REQUEST

Refer to Section 4.8, starting on page 166, of the IRP (Volume A).

a. Please state whether KPC evaluated distributed solar resource options as part of the IRP's risk analysis.

  i. If so, please describe how solar resource options were evaluated, and provide the results of that evaluation.

  ii. If not, please explain why KPC did not perform such an evaluation.

RESPONSE

a. (i) Yes. Distributed resources were evaluated as part of the preferred portfolio. However, they were included with utility-scale solar and wind resources as explained in Section 4.7.2. The Preferred Portfolio was less risky than the "Fossil-only + EcoPower" portfolio as explained in section 4.8.1.

a. (ii) N/A

WITNESS: William K Castle