Integrated Resource Plan

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Technical Appendix

Volume 1

Load Forecast

EAST KENTUCKY
POWER COOPERATIVE
A Touchstone Energy Cooperative

EAST KENTUCKY POWER COOPERATIVE

A Touchstone Energy Cooperative

2014
Load Forecast

Prepared by:
Load Forecasting Department

December 2014

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EXECUTIVE SUMMARY

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Section 1.0
Executive Summary

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, Kentucky, and owned by its 16 member distribution member systems, which serve over 525,000 retail consumers.

EKPC's "2014 Load Forecast" was prepared pursuant to its "2013 Load Forecast Work Plan", which was approved by EKPC's Board of Directors in December 2013 and by the RUS in December 2014. Factors considered when preparing the forecast include regional economic growth, electric appliance saturation and efficiency trends, electricity rates, and weather. The EKPC Load Forecasting Department works with the staff of each member system to prepare its forecast and then aggregates the 16 member system forecasts, adds forecasts of own use and losses, and subtracts planned demand-side management to create EKPC's forecast.

EKPC and its member systems will use the "2014 Load Forecast" for all relevant types of long-term planning, including construction work plans and financial forecasts for the member systems and transmission, generation, demand-side management, and financial planning for EKPC.

1.1.1 Consumer Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2008-2013	0.4%	-53.8%	0.8%	0.5%	-1.3%	2.2%	0.3%
	2014-2019	0.8%	1.4%	1.3%	2.4%	1.3%	0.7%	0.8%
10-Year	2003-2013	1.0%	-31.3%	2.2%	0.1%	1.2%	2.0%	1.0%
	2014-2024	0.9%	1.4%	1.3%	1.6%	1.3%	0.9%	0.9%
15-Year	1998-2013	1.6%	-21.3%	2.9%	2.5%	2.3%	2.0%	1.6%
	2014-2029	0.9%	1.4%	1.3%	1.5%	1.1%	0.9%	0.9%
20-Year	1993-2013	1.9%	-15.3%	3.0%	3.4%	2.5%	2.2%	1.9%
	2014-2034	0.9%	1.4%	1.2%	1.3%	1.0%	0.8%	0.9%

The forecast indicates that, through 2034, total consumers served by member systems will increase from 527,583 to 628,177, an average of 0.9 percent per year.

1.1.2 Energy Sales Growth by Consumer Class

Average Growth Rates	Time Period	Residential	Seasonal Residential	Commercial and Industrial ≤ 1000 KVA	Commercial and Industrial > 1000 KVA	Public Street and Highway Lighting	Other Public Authorities	Total
5-Year	2008-2013	-0.4%	-54.0%	0.5%	-0.4%	0.8%	1.8%	-0.3%
	2014-2019	0.8%	0.6%	1.8%	3.1%	1.5%	1.3%	1.5%
10-Year	2003-2013	1.1%	-31.6%	2.2%	0.5%	2.8%	5.5%	1.1%
	2014-2024	1.0%	1.2%	1.9%	2.5%	1.4%	1.2%	1.5%
15-Year	1998-2013	2.0%	-21.6%	2.8%	2.8%	3.8%	5.2%	2.3%
	2014-2029	1.0%	1.3%	1.9%	2.2%	1.4%	1.1%	1.5%
20-Year	1993-2013	2.5%	-16.1%	3.4%	5.8%	3.4%	5.1%	3.3%
	2014-2034	1.0%	1.2%	1.8%	2.0%	1.2%	1.0%	1.4%

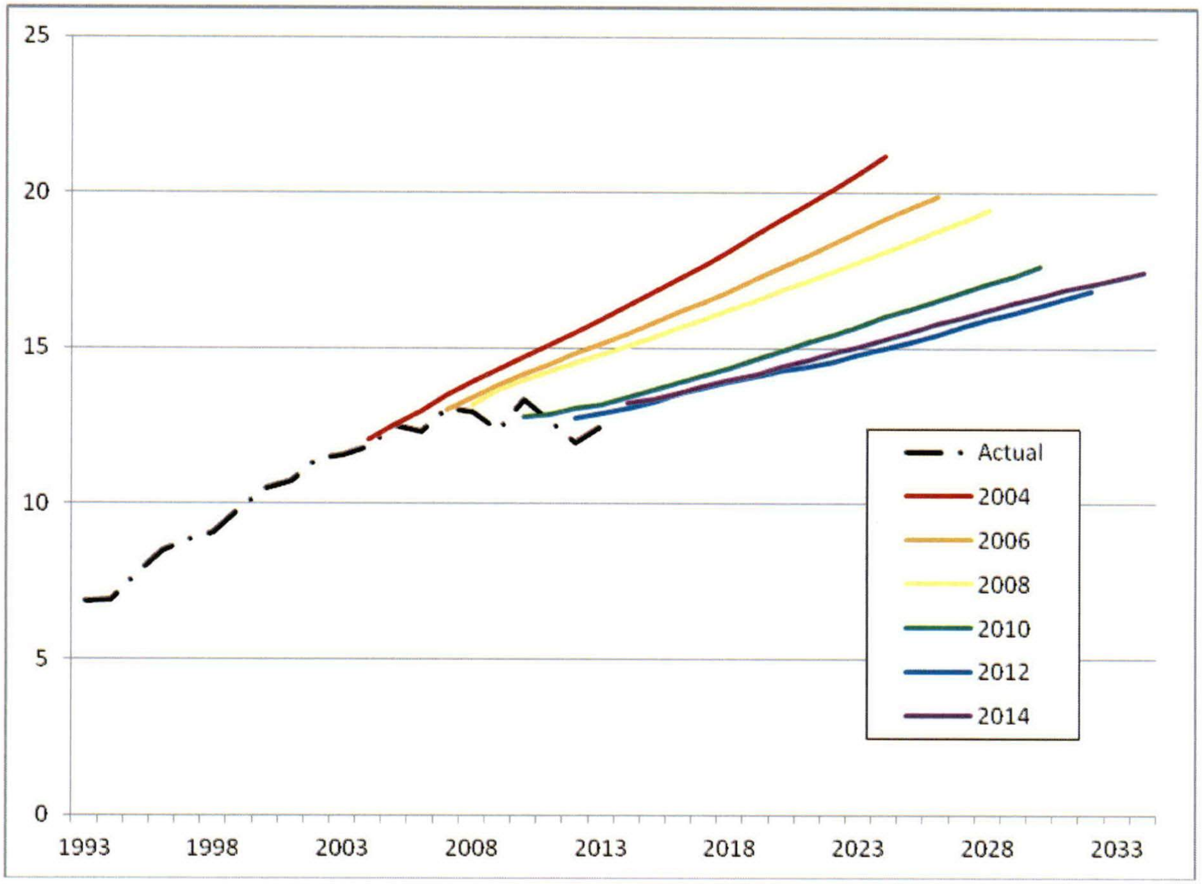
The forecast indicates that, through 2034, total energy sales by member systems will increase from 12.3 to 16.2 million MWh, an average of 1.4 percent per year.

While the growth rates for both consumers and energy sales forecast for the next 5 years are somewhat faster than those of the past 5 years including the recent recession, the growth rates forecast for the next 20 years are less than half of those of the past 20 years.

The commercial and industrial classes are forecast to grow more quickly than the residential class, as has been the case over the long term, such that the residential share of total sales will fall from 58 percent in 2014 to 54 percent in 2034. Despite their relatively fast growth rates, the other classes (in which many member systems do not report any consumers) will each remain less than 1 percent of total sales.

The "2014 Load Forecast" constitutes a slight upward revision in forecasts of most major variables (consumers, total energy requirements, winter peak demand, and summer peak demand) but continues a decade-long pattern of downward revisions to forecasts for consumers in the most-distant years of the load forecast, as economic growth has generally fallen short of projections and long-term economic growth forecasts have been revised downward. It is important to note, however, that the current forecast is closer to the most recent previous forecast than in previous iterations of the long term forecast.

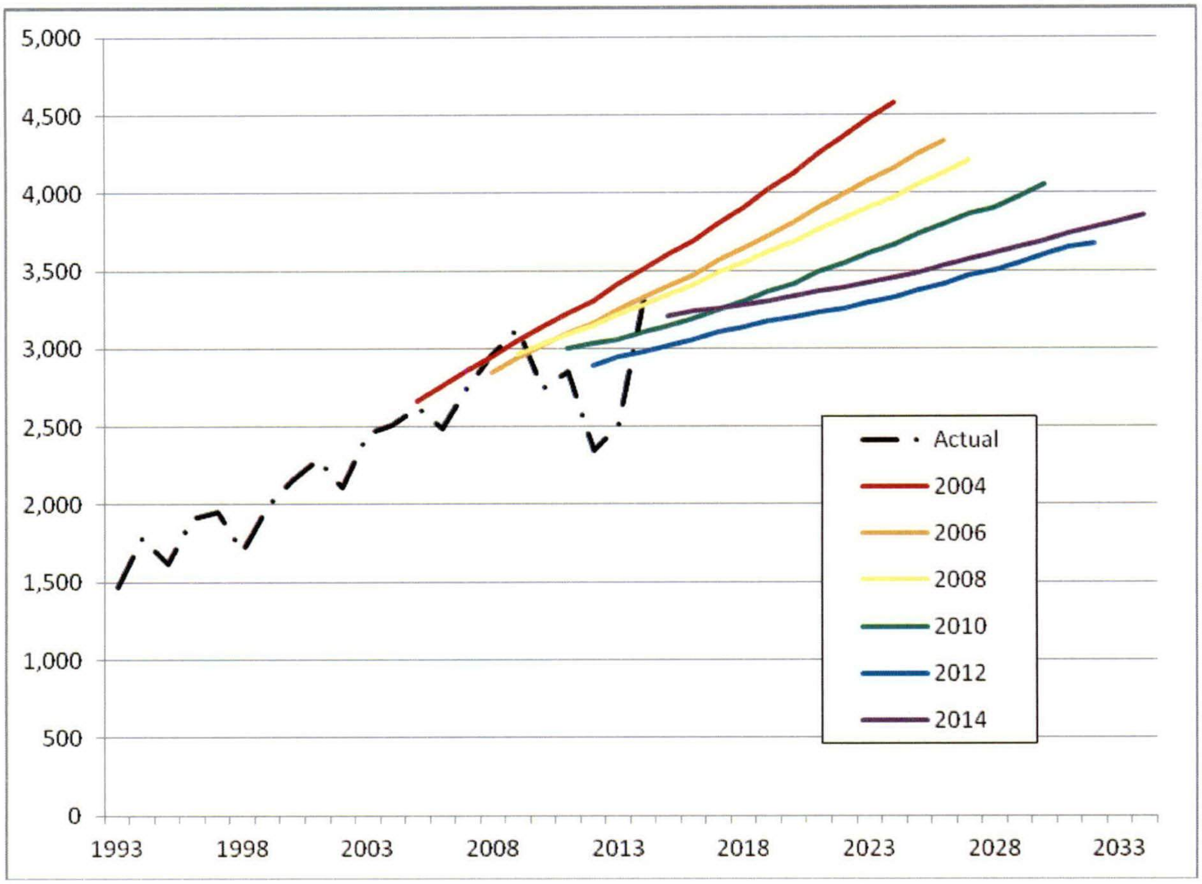
1.2.1 Net Total Energy Requirements (Million MWh) by Load Forecast Vintage



The "2014 Load Forecast" indicates that, through 2034, net total energy requirements will increase from 13.2 to 17.4 million MWh, an average of 1.4 percent per year.

This represents an upward revision from the 2012 Load Forecast by 1.3 percent in the short term and by 1.2 percent in the long term.

1.2.2 Net Winter Peak Demand (MW) by Load Forecast Vintage

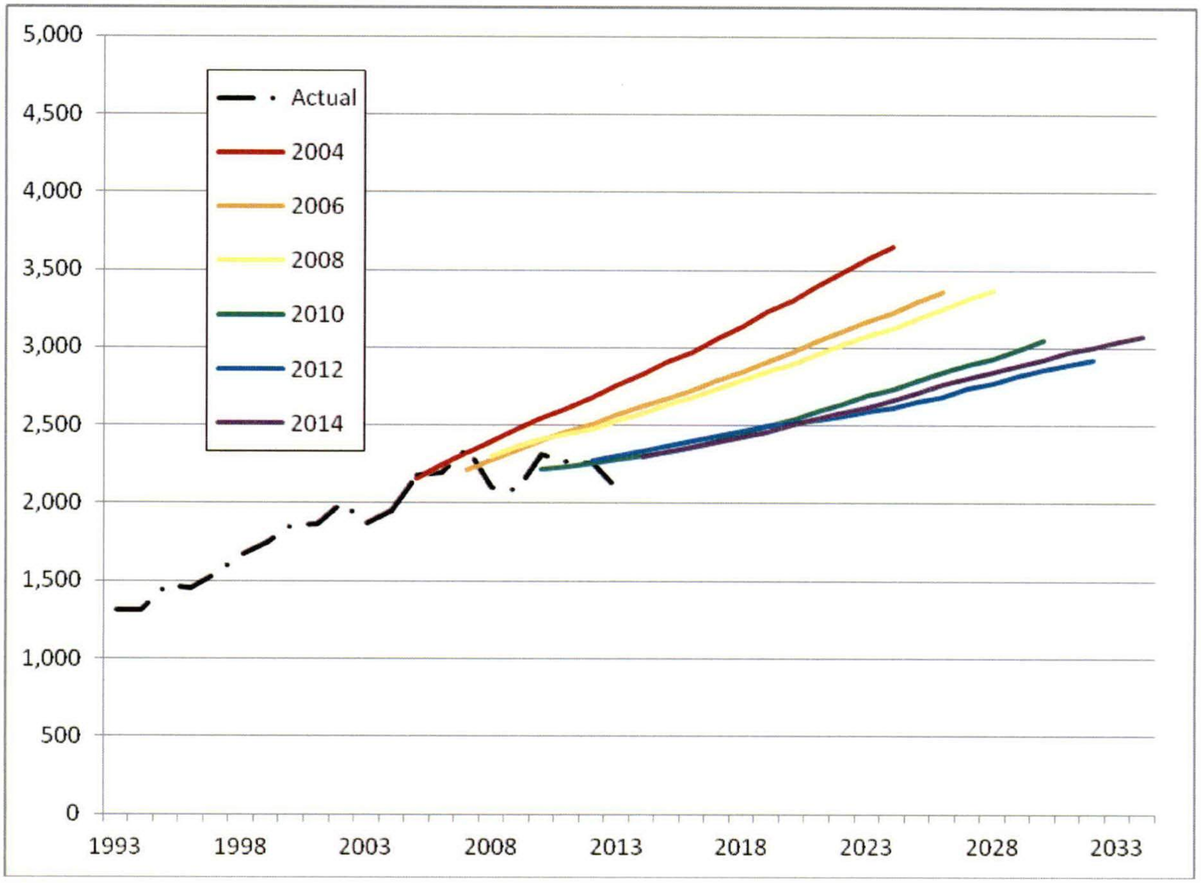


The "2014 Load Forecast" indicates that, through 2034, the net winter peak demand will increase from 3,207 to 3,855 MW, an average of 1.0 percent per year.

This represents an upward revision from the 2012 Load Forecast by 6.3 percent in the short term and by 2.8 percent in the long term.

Because the winter peak demand is forecast to grow less quickly than total energy requirements, the winter peak demand-based load factor will increase, from 47.6 percent in 2015 to 51.7 percent by 2034. Because the EKPC system remains winter-peaking throughout the forecast period, this also represents EKPC's annual load factor.

1.2.3 Net Summer Peak Demand (MW) by Load Forecast Vintage



The "2014 Load Forecast" indicates that, through 2034, the net summer peak demand will increase from 2,302 to 3,075 MW, an average of 1.5 percent per year.

This represents a downward revision from the 2012 Load Forecast by 1.5 percent in the short term and an upward revision by 2.7 percent in the long term.

Because the summer peak demand is forecast to grow at nearly the same rate as total energy requirements, the summer peak demand-based load factor will remain flat at 65 percent through 2034.

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SECTION 2.0

DESCRIPTION OF THE COOPERATIVE

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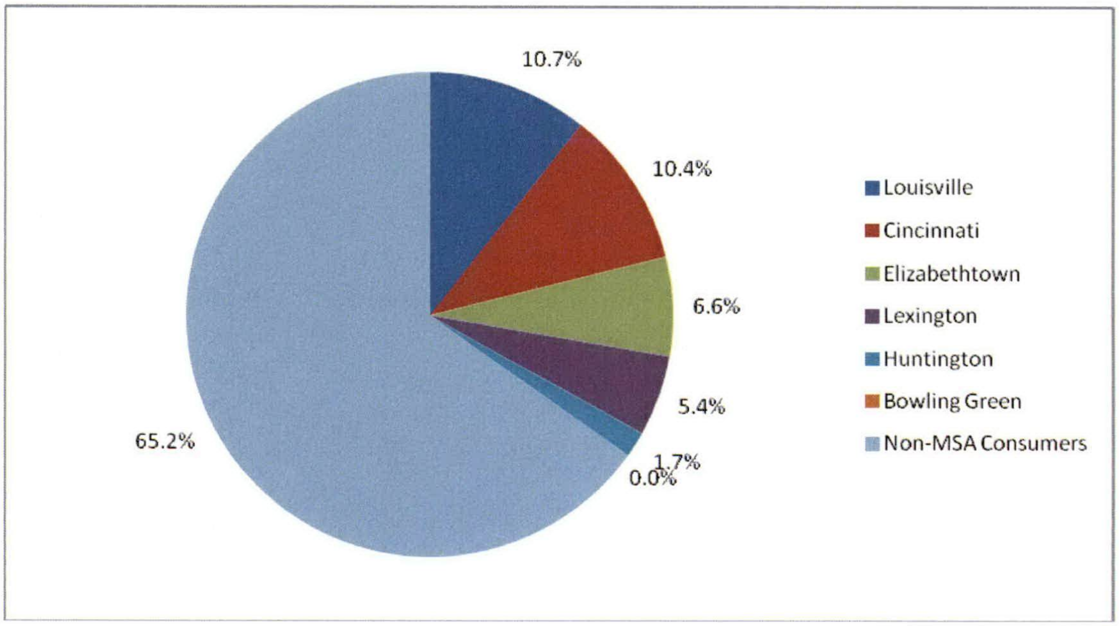
Section 2.0
Description of the Cooperative

East Kentucky Power Cooperative Inc. (EKPC) is a generation and transmission electric cooperative headquartered in Winchester, KY, and owned by its 16 member systems:

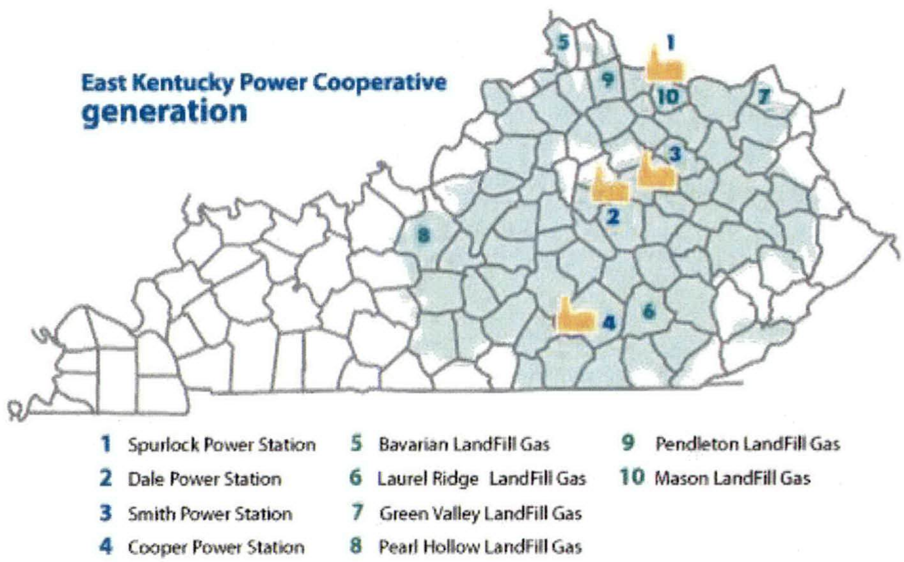
- Big Sandy RECC
- Blue Grass Energy Cooperative
- Clark Energy Cooperative
- Cumberland Valley Electric
- Farmers RECC
- Fleming-Mason Energy Cooperative
- Grayson RECC
- Inter-County Energy Cooperative
- Jackson Energy Cooperative
- Licking Valley RECC
- Nolin RECC
- Owen Electric Cooperative
- Salt River Electric Cooperative
- Shelby Energy Cooperative
- South Kentucky RECC
- Taylor County RECC

Consumers by Metropolitan Statistical Area, 2013

EKPC member systems serve approximately 525,000 consumers in 87 counties in Kentucky and 3 counties in Tennessee, including portions of the Louisville, Cincinnati, Elizabethtown, Lexington, Huntington, and Bowling Green Metropolitan Statistical Areas (MSA). EKPC member systems serve most of the rural areas, while investor-owned and municipal utilities serve most of the cities and towns. Interstates 64, 65, 71, and 75 and several limited-access parkways pass through the area. EKPC member systems' fixed service territory boundaries are on file with the Kentucky Public Service Commission.



EKPC owns a generation fleet of close to 2,900 MW, including coal, natural gas, oil, and landfill gas units, and purchases up to 170 MW of hydro power from the Southeastern Power Administration. EKPC also owns more than 2,900 miles of transmission line and approximately 400 substations.



Generation includes:

- Spurlock – 1,346 net MW
- Dale – 150 net MW
- Smith Combustion Turbine Units
  - Summer – 768 net MW
  - Winter – 1,016 net MW
- Cooper – 341 net MW
- Landfill Gas Plants
  - Bavarian – 3.0 net MW
  - Laurel Ridge – 3.0 net MW
  - Green Valley – 2.3 net MW
  - Pearl Hollow – 2.3 net MW
  - Pendleton – 3.0 net MW
- Southeastern Power Administration (SEPA), hydro power – 170 MW

SECTION 3.0

DESCRIPTION OF THE FORECASTING METHOD

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Section 3.0
Description of the Forecasting Method

EKPC's "2014 Load Forecast" was prepared pursuant to its "2013 Load Forecast Work Plan", which was approved by EKPC's Board of Directors in December 2013 and by the RUS in December 2014. Factors considered when preparing the forecast include regional economic growth, electric appliance saturation and efficiency trends, electricity rates, and weather. The EKPC Load Forecasting Department works with the staff of each member system to prepare its forecast and then aggregates the 16 member system forecasts, adds forecasts of own use and losses, and subtracts planned demand-side management to create EKPC's forecast.

EKPC and its member systems will use the "2014 Load Forecast" for all relevant types of long-term planning, including construction work plans and financial forecasts for the member systems and transmission, generation, demand-side management, and financial planning for EKPC.

3.1 Model Inputs

The following section describes the independent variables used in EKPC's models of consumers and energy sales by consumer class for each member system.

3.1.1 Regional Economic Growth

EKPC combines county-level forecasts from IHS Global Insight into regional economic forecasts based roughly on member system service territory boundaries. Member systems and counties are assigned to regions as follows:

- Central Region:
  member systems: Blue Grass Energy Cooperative
  counties: Anderson, Bourbon, Clark, Fayette, Franklin, Harrison, Jessamine, Madison, Mercer, Scott, and Woodford
- East Region:
  member systems: Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, and Licking Valley RECC
  counties: Bell, Breathitt, Clay, Estill, Floyd, Harlan, Jackson, Johnson, Knott, Knox, Laurel, Lee, Leslie, Letcher, Magoffin, Martin, Morgan, Owsley, Perry, Pike, Rockcastle, Whitley, and Wolfe
- North Region:
  member systems: Owen Electric Cooperative
  counties: Boone, Bracken, Campbell, Carroll, Gallatin, Grant, Kenton, Owen, and Pendleton
- North Central Region:
  member systems: Nolin RECC, Salt River Electric Cooperative, and Shelby Energy Cooperative
  counties: Bullitt, Hardin, Henry, Jefferson, Larue, Meade, Nelson, Oldham, Shelby, Spencer, Trimble, and Washington
- North East Region:
  member systems: Clark Energy Cooperative, Fleming-Mason Energy Cooperative, and Grayson RECC
  counties: Bath, Boyd, Carter, Elliott, Fleming, Greenup, Lawrence, Lewis, Mason, Menifee, Montgomery, Nicholas, Powell, Robertson, and Rowan
- South Region:
  member systems: Inter-County Energy Cooperative, South Kentucky RECC, and Taylor County RECC
  counties: Adair, Boyle, Casey, Garrard, Green, Lincoln, Marion, McCreary, Pulaski, Russell, Taylor, and Wayne
- South Central Region:
  member system: Farmers RECC
  counties: Allen, Barren, Butler, Cumberland, Edmonson, Grayson, Hart, Metcalfe, Monroe, Simpson, and Warren

EKPC calculates each member system's share of its region's economy by dividing its actual (as adjusted for reclassifications) and forecast residential consumer count by the total number of households in the region. The share is then applied to all economic variables (including households, employment, population, real gross county product and total real personal income) before they are used in other models.

The "2014 Load Forecast" is based on IHS Global Insight's county-level economic forecasts released on March 1, 2014.

3.1.2 Electric Appliance Saturation and Efficiency Trends

Every 2-3 years since 1981, EKPC has surveyed its member systems' residential consumers to gather information on electric appliance saturation and other factors affecting electricity demand. EKPC projects these saturations for each member system as a function of time. The "2014 Load Forecast" incorporates data from surveys through EKPC's "2013 Owner-Member Residential Customer Analysis".

EKPC is a member of Itron's Energy Forecasting Group and as such, receives from Itron electric appliance efficiency projections for the East South Central U.S. Census Division (which comprises the states of Alabama, Kentucky, Mississippi, and Tennessee) based on information from the Energy Information Administration (EIA). The projections used in the "2014 Load Forecast" are from Itron's "2013 Residential Statistically Adjusted End-use (SAE) Spreadsheets" and incorporate data from EIA's "Annual Energy Outlook 2013".

3.1.3 Electricity Rates

The wholesale power cost projections used in the "2014 Load Forecast" are from EKPC's "Ten-Year Financial Forecast, 2013-2022", which was approved by EKPC's Board of Directors in October 2013.

3.1.4 Weather

The forecasts rely on NOAA weather stations located at seven airports in or near the EKPC system. Normals for most member systems are based on "1981-2010 U.S. Climate Normals". Member systems are assigned to airports as follows:

- Blue Grass Airport (LEX) in Lexington, KY:
  member systems: Blue Grass Energy Cooperative, Clark Energy Cooperative, and Inter-County Energy Cooperative
- Bowling Green/Warren County Regional Airport (BWG) in Bowling Green, KY:
  member systems: Farmers RECC and Taylor County RECC
- Cincinnati/Northern Kentucky International Airport (CVG) in Covington, KY:
  member systems: Fleming-Mason Energy Cooperative and Owen Electric Cooperative
- Huntington Tri-State Airport (HTS) in Huntington, WV:
  member system: Grayson RECC
- Julian Carroll Airport (JKL) in Jackson, KY:
  member systems: Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, and Licking Valley RECC
- Louisville International Airport (SDF) in Louisville, KY:
  member systems: Nolin RECC, Salt River Electric Cooperative, and Shelby Energy Cooperative
- Pulaski County Airport (SME) in Somerset, KY:
  member system: South Kentucky RECC

3.2 Models of Consumers and Energy Sales by Consumer Class

The following section describes EKPC's models of consumers and energy sales by consumer class for each member system. In cases of reclassification of consumers or data errors on RUS Form 7, the models include binary variables to account for these shifts or spikes in the data.

3.2.1 Residential

As of 2013, residential consumers account for 58.1 percent of total energy sales at the EKPC system level.

EKPC models the annual residential consumers and monthly residential energy sales as a function of various economic variables where appropriate. These variables include

- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms

3.2.2 Seasonal Residential

As of 2013, only one member system reports seasonal residential consumers, which account for 0.1 percent of total energy sales at the EKPC system level.

EKPC models the annual seasonal residential consumers and monthly seasonal residential energy sales as a function of various economic variables.

3.2.3 Commercial and Industrial ≤ 1000 KVA

As of 2013, commercial and industrial ≤ 1000 KVA consumers account for 16.1 percent of total energy sales at the EKPC system level.

EKPC models the annual commercial and industrial ≤ 1000 KVA consumers and monthly commercial and industrial ≤ 1000 KVA energy sales as a function of various economic variables where appropriate. These variables include:

- Residential customer counts
- Households
- Population density

- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms

3.2.4 Commercial and Industrial > 1000 KVA

As of 2013, commercial and industrial > 1000 KVA consumers account for 25.4 percent of total energy sales at the EKPC system level.

EKPC models the annual commercial and industrial > 1000 KVA consumers based on input from the individual member systems and monthly commercial and industrial ≤ 1000 KVA energy sales are modeled as a function of the real gross county product for that given service territory. Member systems remain in regular contact with their largest consumers and are generally aware of current production and future expansion plans, so they project energy sales for existing consumers and indentified expected new consumers in this class for the next 3 years.

3.2.5 Public Street and Highway Lighting

As of 2013, 12 member systems report public street and highway lighting consumers, which account for 0.1 percent of total energy sales at the EKPC system level.

EKPC models the annual public street and highway lighting consumers and monthly public street and highway lighting energy sales as a function of various economic variables where appropriate. These variables include:

- Residential customer counts
- Households
- Population density
- Autoregressive terms

3.2.6 Other Public Authorities

As of 2013, only two member systems report other public authorities consumers, which account for 0.3 percent of total energy sales at the EKPC system level.

EKPC models the annual other public authorities consumers and monthly other public authorities energy sales as a function of various economic variables where appropriate. These variables include:

- Residential customer counts
- Households
- Population density
- Employment
- Real gross county product
- Real total personal income
- Consumer price index
- Base 55 heating degree days
- Base 30 heating degree days
- Base 65 cooling degree days
- Autoregressive terms

3.3 Calculations

The following section describes various calculations that are performed after consumers and energy sales by consumer class for each member system have been forecast.

3.3.1 Own Use

For EKPC and each member system, future own use is assumed to be the average of recent own use, unless there is a specific reason to assume otherwise.

3.3.2 Losses

Future member system distribution and EKPC transmission losses are assumed to be the average of actual losses with adjustments based on input from member systems or EKPC concerning any system improvements.

3.3.3 Seasonal Peaks

Future seasonal peak demands are calculated by applying load factors for winter and summer to total purchased power for each member system. EKPC adjusts these load factors to match recent data as closely as possible.

3.3.4 Demand-Side Management

For more than 30 years, EKPC and its member systems have proactively helped consumers identify opportunities to improve the energy efficiency of their homes and businesses and to shift their consumption from on-peak to off-peak hours, offering a variety of options to achieve these goals. EKPC considers these demand-side management (DSM) programs as part of its overall resource portfolio, as they can delay the need for additional generating capacity. The "2014 Load Forecast" incorporates EKPC's current 5-year DSM implementation plan and an assumption of similar levels of implementation in subsequent years.

3.4 Development of Alternative Economic and Weather Scenarios

In addition to the forecasted peaks, high and low cases are developed. The same methodology is used, however, the starting summary file is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in optimistic economic growth and extreme weather conditions and one reflecting pessimistic economic growth and mild weather conditions. The assumptions that are varied include:

1. Weather: based on historical heating and cooling degree day data, alternate weather projections were developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively. The resulting forecasts reflect cases assuming base case annual degree days +/-20%.

2. Electric price: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates around the growth patterns for the base case residential price forecast.

   Therefore, the high scenario for the residential price forecast is constructed to have a 3.2% compound annual growth rate, while the low scenario is constructed to have a 1.6% compound annual growth rate. The adjustments to growth rate are applied to the base case on an annual basis.

3. Residential customers: In the EKPC base case load forecast for 2014 through 2034, the projected number of residential customers increases at a growth rate of 0.9%. The basic approach to preparing high and low case scenarios for the future number of residential customers is to determine the magnitude of variation in the past between long term average growth rates and higher or lower growth rates during shorter periods of time.

   These resulting adjustments were applied to the 20 year compound annual growth rate in the base case customer count forecast resulting in a high customer case of 1.6% growth rate and 0.3% for the low case growth rate. This relationship was preserved in preparing the monthly customer counts for the high and low case scenarios.

4. Small and Large Commercial customer and energy – Small commercial customer growth is correlated to residential customer growth and the relationship was maintained when developing the high and low cases. Therefore, based upon the resulting high and low residential customer forecasts, the small commercial customers were impacted accordingly. For the large class, given year to year customer change is small, the low case was based upon no new customers for the forecast period. The high case was based on adding one new customer per year. For energy, small and large commercial usage is not as weather sensitive as residential usage, however, price does impact usage. Therefore, the low case assumes the higher prices while the high case assumes the lower prices.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts. The following cases were developed:

Low Case - Pessimistic economic assumptions with mild weather causing lower loads
Base Case - Most probable economics assumptions with normal weather (Base Case pre DSM)
High Case - Optimistic economic assumptions with severe weather causing higher loads.

SECTION 4.0

KEY ASSUMPTIONS

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Section 4.0
Key Assumptions

4.1.0 Regional Economic Growth

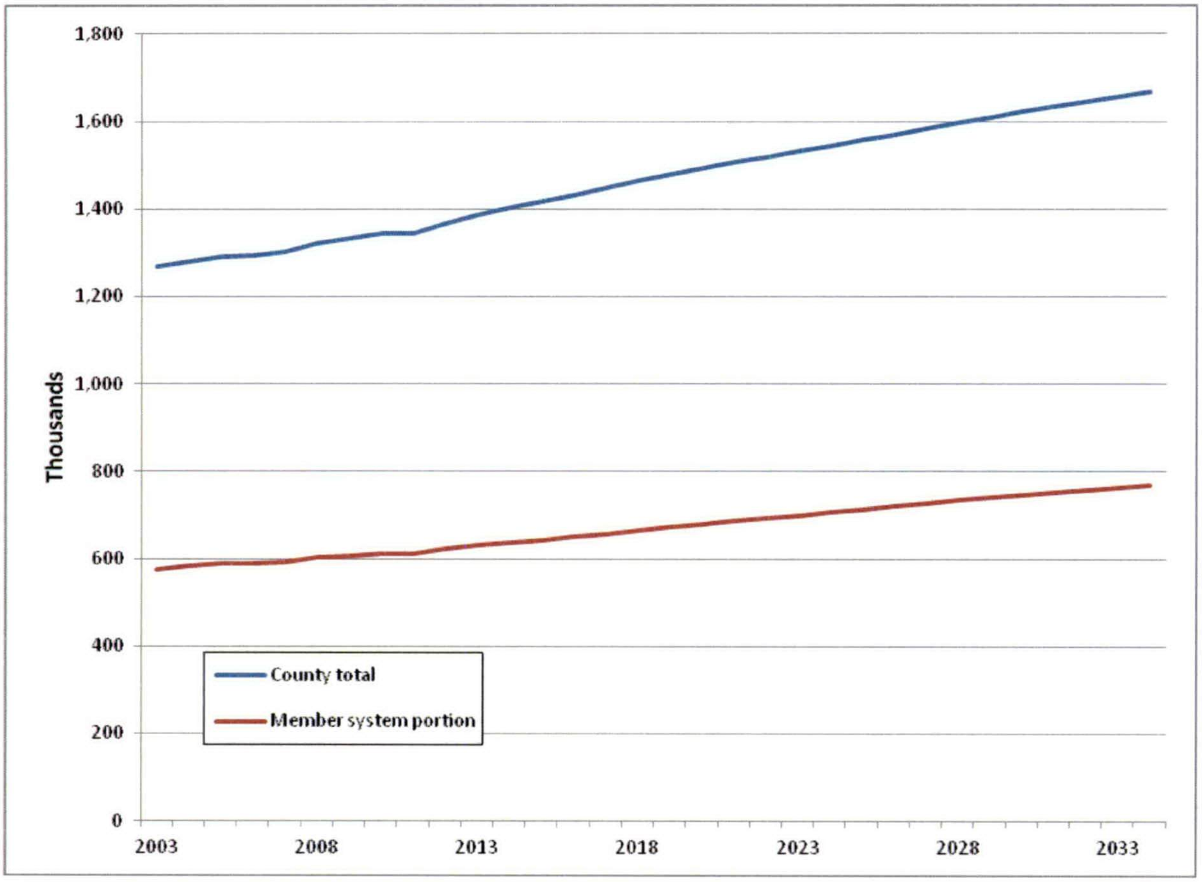
Average Growth Rates	Time Period	Households		Employment		Total Real Personal Income	
		County Total	Co-op Portion	County Total	Co-op Portion	County Total	Co-op Portion
5-Year	2008-2013	1.0%	1.0%	-0.1%	-0.2%	1.2%	1.4%
	2014-2019	1.1%	1.1%	1.9%	1.5%	3.8%	3.4%
10-Year	2003-2013	0.9%	0.9%	0.3%	0.3%	1.7%	2.0%
	2014-2024	1.0%	0.7%	1.4%	0.8%	3.5%	2.8%
15-Year	1998-2013	1.0%	1.0%	0.4%	0.6%	2.1%	2.3%
	2014-2029	1.0%	0.6%	1.2%	0.4%	3.4%	2.5%
20-Year	1993-2013	1.1%	1.2%	0.9%	1.2%	2.6%	2.9%
	2014-2034	1.0%	0.5%	1.0%	0.2%	3.2%	2.2%

Although the growth rates in the member systems' service territories have for the most part exceeded those in the region as a whole in the past, the opposite is expected to be true going forward.

While the growth rates for both households and employment in the member systems' service territories forecasted for the next 5 years are somewhat faster than those of the past 5 years including the recent recession, the growth rates forecast for the next 20 years are about half of those of the past 20 years.

Employment is forecast to growth faster than households in the short term, but is expected to have slower growth in the long term. Real personal income per household is forecast to grow more quickly than it has in the past, primarily due to the replacement of lower-paying jobs with fewer higher-paying jobs.

4.1.1 Households



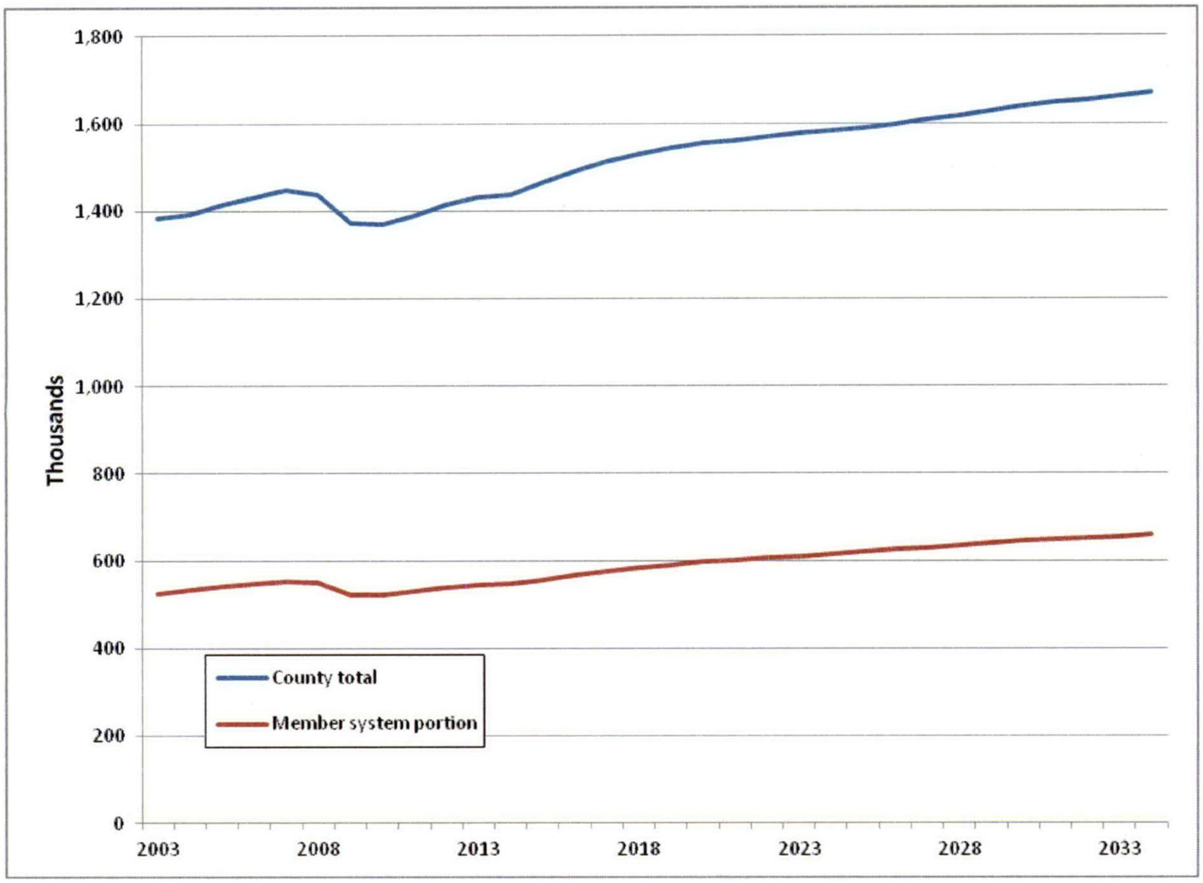
The forecast indicates that, through 2034, total households will increase from 1,402,814 to 1,667,273, an average of 1.0 percent per year, while the member system portion will increase from 637,628 to 768,416, an average of 0.5 percent per year.

The North Central Region is forecast to grow most quickly, at 1.6 percent per year, while the East Region is forecast to experience the least amount of growth, with it remaining flat.

Regional Households

Year	Central	East	North	North Central	North East	South	South Central
2003	244,025	213,729	159,010	138,140	105,132	106,208	105,644
2004	247,251	213,270	160,984	141,347	105,254	107,664	106,908
2005	250,400	212,555	162,705	144,038	105,627	108,431	108,209
2006	252,424	210,486	163,474	145,724	105,385	108,331	108,833
2007	254,930	209,830	164,924	147,683	105,419	108,228	109,694
2008	260,569	210,950	167,858	150,820	106,571	109,629	111,728
2009	264,100	210,931	169,506	152,646	106,763	110,202	112,806
2010	267,396	211,295	171,480	155,158	107,292	111,160	114,262
2011	267,920	210,216	172,919	155,466	106,872	110,993	115,439
2012	272,239	212,166	176,842	158,642	107,972	113,039	118.874
2013	277,614	213,148	180,092	161,837	108,637	114,202	120,754
2014	281,970	212,970	182,508	164,724	109,060	114,847	122,150
2015	285,935	212,843	184,588	167,720	109,392	115,567	123,670
2016	289,975	213,018	186,938	170,640	109,953	116,476	125,161
2017	294,170	213,499	189,250	173,717	110,773	117,609	126,527
2018	298,472	214,042	191,649	176,804	111,665	118,812	127,849
2019	302,412	214,299	193,917	179,873	112,428	119,900	128,976
2020	306,093	214,339	196,037	183,057	113,092	120,899	129,975
2021	309,853	214,367	198,202	186,222	113,680	121,912	130,874
2022	313,312	214,120	200,111	189,533	114,165	122,796	131,770
2023	316,722	213,826	201,970	192,632	114,611	123,683	132,580
2024	320,239	213,657	203,749	195,944	115,147	124,672	133,502
2025	323,895	213,589	205,596	199,337	115,691	125,747	134,528
2026	327,479	213,548	207,579	202,812	116,298	126,859	135,626
2027	331,011	213,752	209,697	206,058	116,904	127,917	136,776
2028	334,447	213,772	211,866	209,329	117,523	128,873	138,004
2029	337,822	213,918	214,024	212,145	118,138	129,815	139,211
2030	340,975	213,975	216,088	214,805	118,684	130,668	140,338
2031	343,893	214,062	218,031	217,358	119,038	131,390	141,123
2032	346,777	214,046	219,925	220,098	119,433	132,031	142,171
2033	349,795	214,060	221,896	222,741	119,847	132,700	143,249
2034	352,988	214,112	223,985	225,529	120,277	133,397	144,394

4.1.2 Employment



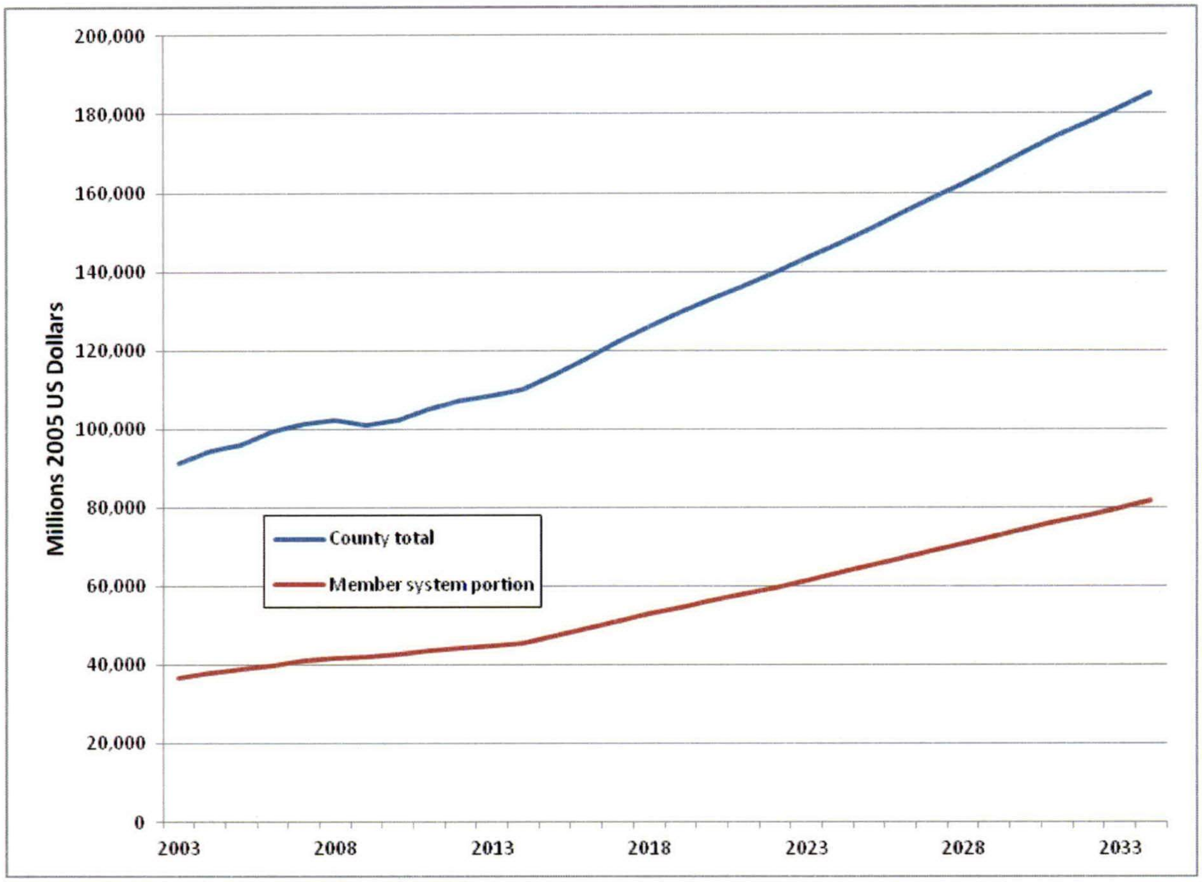
The forecast indicates that, through 2034, total employment will increase from 1,438,340 to 1,670,019, an average of 1.0 percent per year, while the member system portion will increase from 545,903 to 658,841, an average of 0.2 percent per year.

The North Central Region is forecast to grow most quickly, at 1.1 percent per year, while the East Region is forecast to experience the least amount of growth, at 0.3 percent per year.

Regional Employment

Year	Central	East	North	North Central	North East	South	South Central
2003	323,703	164,411	181,973	112,068	93,630	92,352	110,948
2004	325,456	166,803	185,178	115,215	93,516	92,866	113,239
2005	332,497	168,582	189,907	116,567	94,026	94,317	115,423
2006	337,811	169,215	191,546	119,623	94,632	96,099	116,284
2007	341,516	168,901	195,270	122,416	95,334	96,393	117,829
2008	336,822	169,000	195,909	124,732	94,140	94,944	116,362
2009	321,785	163,711	185,870	119,786	89,298	90,314	108,856
2010	323,658	161,195	185,817	120,149	89,515	90,736	109,693
2011	328,932	161,821	189,218	122,712	89,000	90,787	112,331
2012	334,928	159,044	192,997	126,930	89,249	91,161	115,953
2013	340,825	153,859	196,023	130,285	88,713	90,809	116,913
2014	342,708	152,084	199,081	131,552	88,763	90,808	118,495
2015	350,152	153,791	202,386	134,114	90,478	92,561	120,907
2016	356,953	155,723	206,176	136,737	92,201	94,341	123,206
2017	362,828	157,172	208,950	139,007	93,757	95,921	125,082
2018	367,406	158,182	211,988	141,028	95,001	97,109	126,419
2019	371,196	158,867	214,585	142,847	95,842	98,054	127,517
2020	374,603	159,431	217,182	144,884	96,531	98,925	128,482
2021	376,663	159,328	218,613	145,833	96,869	99,492	129,003
2022	378,995	159,336	220,228	147,191	97,282	100,209	129,618
2023	381,588	159,461	222,048	148,694	97,658	100,932	130,220
2024	384,059	159,557	223,289	150,273	98,085	101,717	130,857
2025	386,179	159,559	224,365	151,792	98,454	102,497	131,498
2026	388,415	159,542	226,132	153,397	98,902	103,300	132,160
2027	390,863	159,645	228,271	154,813	99,392	104,065	132,807
2028	393,552	160,039	230,716	156,210	99,989	104,922	133,583
2029	395,943	160,393	232,966	157,462	100,552	105,703	134,272
2030	398,714	160,849	235,564	158,959	101,161	106,530	135,016
2031	400,543	161,072	237,451	159,525	101,533	107,081	135,515
2032	402,581	161,348	239,208	160,404	101,949	107,656	136,048
2033	404,616	161,594	241,352	161,275	102,324	108,195	136,549
2034	406,915	161,960	243,457	162,263	102,765	108,819	137,147

4.1.3 Total Real Personal Income



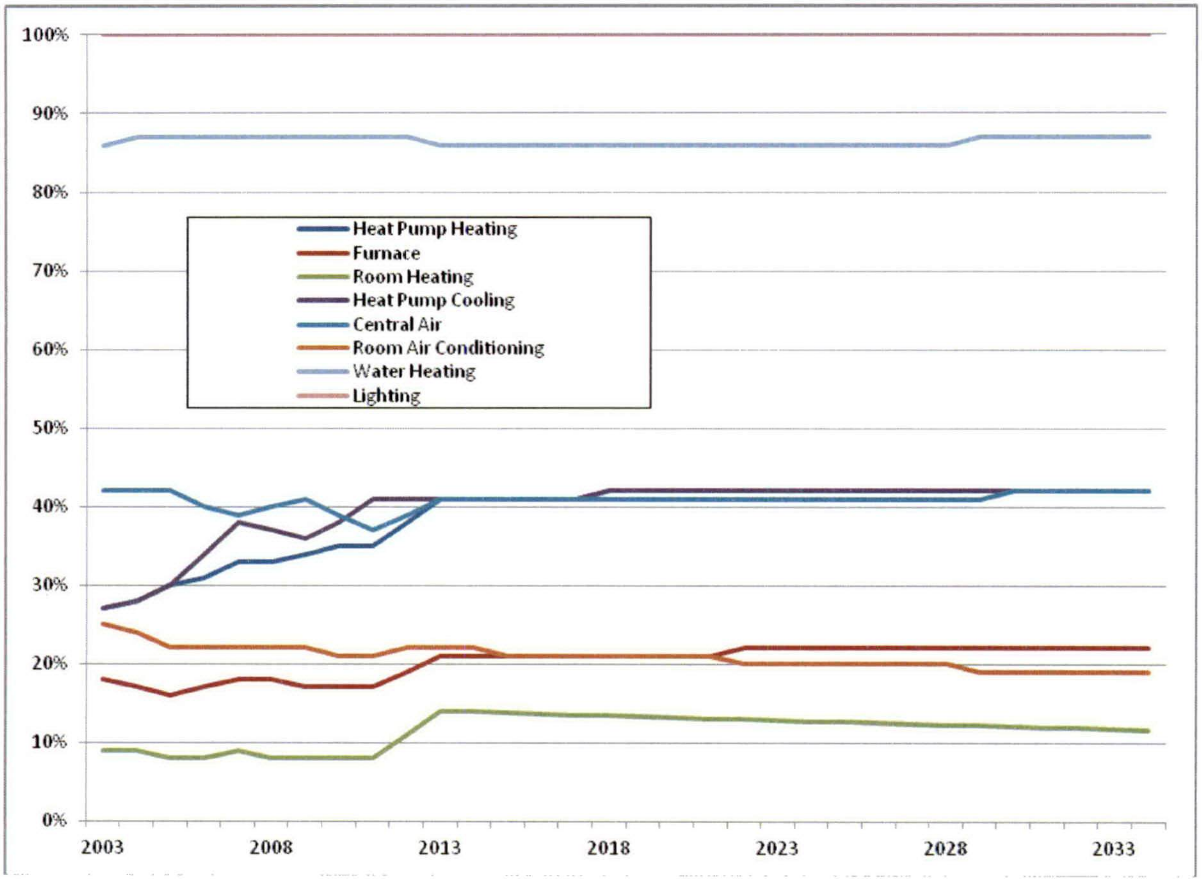
The forecast indicates that, through 2034, total county real personal income (2005 U.S. dollars) will increase from $110.0 billion to $185.4 billion, an average of 2.6 percent per year, while the member system portion will increase from $45.6 billion to $81.6 billion, an average of 3.0 percent per year.

The North Central Region is forecast to grow most quickly, at 3.9 percent per year, while the East Region is forecast to grow least quickly, at 1.9 percent per year.

Regional Total Real Personal Income (Millions 2005 U.S. Dollars)

Year	Central	East	North	North Central	North East	South	South Central
2003	19,065	11,216	13,042	10,747	6,185	5,894	6,368
2004	19,655	11,535	13,480	11,285	6,302	6,103	6,705
2005	20,050	11,784	13,777	11,539	6,360	6,206	6,879
2006	20,934	12,043	14,216	12,035	6,552	6,349	7,061
2007	21,412	12,256	14,460	12,439	6,713	6,536	7,218
2008	21,527	12,790	14,492	12,663	6,906	6,656	7,385
2009	21,139	13,092	14,313	12,714	6,922	6,693	7,279
2010	21,394	13,145	14,381	13,265	7,004	6,773	7,439
2011	22,057	13,279	15,037	13,885	7,065	6,859	7,686
2012	22,502	13,112	15,533	14,072	7,152	6,934	7,857
2013	22,821	12,932	15,816	14,319	7,190	6,976	7,950
2014	23,167	13,024	16,135	14,689	7,280	7,110	8,164
2015	24,041	13,338	16,654	15,393	7,508	7,348	8,435
2016	25,017	13,748	17,261	16,232	7,788	7,641	8,768
2017	25,957	14,124	17,839	17,058	8,038	7,928	9,098
2018	26,829	14,487	18,400	17,769	8,280	8,199	9,377
2019	27,714	14,749	18,993	18,565	8,485	8,411	9,616
2020	28,483	15,013	19,531	19,359	8,698	8,632	9,843
2021	29,186	15,267	19,991	20,061	8,894	8,860	10,064
2022	29,943	15,554	20,516	20,858	9,109	9,118	10,303
2023	30,774	15,832	21,114	21,738	9,309	9,368	10,536
2024	31,582	16,094	21,689	22,680	9,511	9,624	10,776
2025	32,437	16,374	22,263	23,592	9,719	9,903	11,050
2026	33,355	16,633	22,883	24,539	9,920	10,173	11,294
2027	34,213	16,901	23,504	25,431	10,147	10,440	11,539
2028	35,117	17,177	24,129	26,320	10,354	10,703	11,795
2029	36,042	17,457	24,786	27,194	10,561	10,962	12,048
2030	37,004	17,759	25,479	28,114	10,777	11,235	12,313
2031	37,918	18,046	26,098	28,911	10,975	11,485	12,542
2032	38.789	18,333	26,674	29,708	11,179	11,735	12,777
2033	39,671	18,628	27,271	30,491	11,382	11,992	13,002
2034	40,570	18,937	27,894	31,323	11,602	12,261	13,248

4.2.1 Electric Appliance Saturation Trends



Every two to three years since 1981, EKPC has surveyed the member systems' residential customers. The most recent survey was conducted in 2013. EKPC gathers appliance, insulation, heating and cooling, economic, and demographic data. Appliance holdings of survey respondents are analyzed in order to better understand their electricity consumption and to project future appliance saturations.

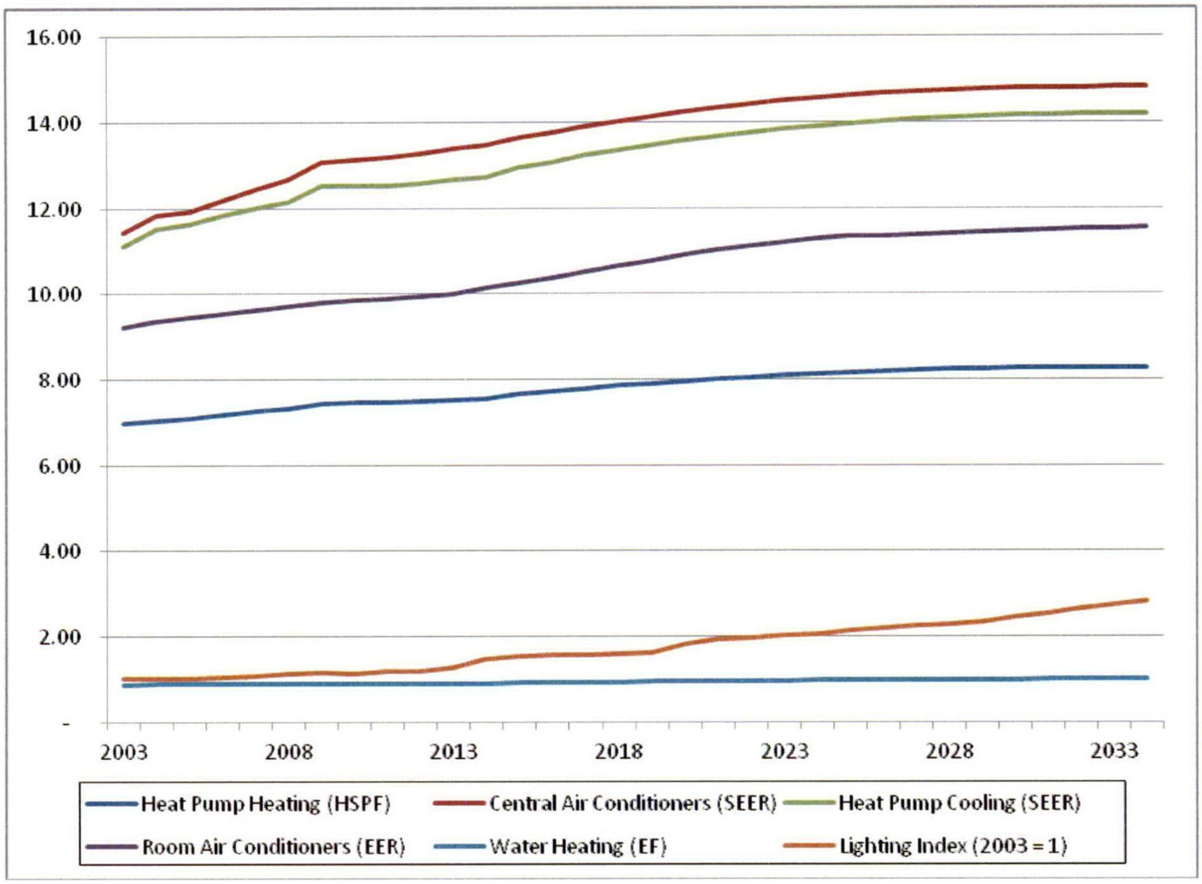
The saturation of electric heating is projected to continue to increase, with consumers installing more-efficient heating appliances such as heat pumps rather than individual room heaters. About 63% of customers have electricity as a main heating source, while 17.6% have it as a secondary source.

Nearly all homes have electric cooling of some type, with the saturation of room air conditioning projected to continue to decline in favor of heat pump and central air in new homes.

Electric Appliance Saturation Trends

Year	Heat Pump Heating	Furnace	Room Heating	Heat Pump Cooling	Central Air	Room Air Conditioning	Water Heating	Lighting
2003	27%	18%	9%	27%	42%	25%	86%	100%
2004	28%	17%	9%	28%	42%	24%	87%	100%
2005	30%	16%	8%	30%	42%	22%	87%	100%
2006	31%	17%	8%	34%	40%	22%	87%	100%
2007	33%	18%	9%	38%	39%	22%	87%	100%
2008	33%	18%	8%	37%	40%	22%	87%	100%
2009	34%	17%	8%	36%	41%	22%	87%	100%
2010	35%	17%	8%	38%	39%	21%	87%	100%
2011	35%	17%	8%	41%	37%	21%	87%	100%
2012	38%	19%	11%	41%	39%	22%	87%	100%
2013	41%	21%	14%	41%	41%	22%	86%	100%
2014	41%	21%	14%	41%	41%	22%	86%	100%
2015	41%	21%	14%	41%	41%	21%	86%	100%
2016	41%	21%	14%	41%	41%	21%	86%	100%
2017	41%	21%	14%	41%	41%	21%	86%	100%
2018	42%	21%	13%	42%	41%	21%	86%	100%
2019	42%	21%	13%	42%	41%	21%	86%	100%
2020	42%	21%	13%	42%	41%	21%	86%	100%
2021	42%	21%	13%	42%	41%	21%	86%	100%
2022	42%	22%	13%	42%	41%	20%	86%	100%
2023	42%	22%	13%	42%	41%	20%	86%	100%
2024	42%	22%	13%	42%	41%	20%	86%	100%
2025	42%	22%	13%	42%	41%	20%	86%	100%
2026	42%	22%	13%	42%	41%	20%	86%	100%
2027	42%	22%	12%	42%	41%	20%	86%	100%
2028	42%	22%	12%	42%	41%	20%	86%	100%
2029	42%	22%	12%	42%	41%	19%	87%	100%
2030	42%	22%	12%	42%	42%	19%	87%	100%
2031	42%	22%	12%	42%	42%	19%	87%	100%
2032	42%	22%	12%	42%	42%	19%	87%	100%
2033	42%	22%	12%	42%	42%	19%	87%	100%
2034	42%	22%	12%	42%	42%	19%	87%	100%

4.2.2 Electric Appliance Efficiency Trends



The preceding efficiency trends are from Itron's 2014 Residential Statistically Adjusted End-Use Spreadsheets, which are in turn based on the Energy Information Administration's (EIA) 2014 Annual Energy Outlook (AEO).

The efficiencies of heat pumps and air conditioners are expected to increase during the forecast period. Efficiencies in lighting are also expected to increase significantly through 2034, as LED technology is projected to gain a significant share of the overall lighting technologies.

Year	Heat Pump Heating (HSPF)	Furnace (HSPF)	Room Heating Index (2003=1)	Heat Pump Cooling (SEER)	Central Air (SEER)	Room Air Conditioning (EER)	Water Heating (EF)	Lighting (2003=1)
2003	6.98	3.41	1.00	11.11	11.44	9.22	0.88	1.00
2004	7.03	3.41	1.00	11.51	11.82	9.37	0.88	1.00
2005	7.10	3.41	1.01	11.64	11.92	9.46	0.88	1.00
2006	7.18	3.41	1.03	11.82	12.17	9.54	0.89	1.03
2007	7.26	3.41	1.06	12.01	12.43	9.62	0.89	1.07
2008	7.32	3.41	1.09	12.16	12.66	9.71	0.89	1.11
2009	7.45	3.41	1.12	12.52	13.07	9.80	0.89	1.14
2010	7.46	3.41	1.14	12.52	13.13	9.85	0.89	1.14
2011	7.47	3.41	1.17	12.52	13.19	9.89	0.90	1.17
2012	7.49	3.41	1.20	12.58	13.28	9.94	0.90	1.19
2013	7.52	3.41	1.24	12.66	13.40	9.99	0.90	1.27
2014	7.55	3.41	1.27	12.72	13.48	10.15	0.90	1.47
2015	7.66	3.41	1.31	12.94	13.64	10.26	0.91	1.52
2016	7.73	3.41	1.33	13.08	13.77	10.38	0.92	1.54
2017	7.80	3.41	1.35	13.23	13.90	10.51	0.93	1.56
2018	7.86	3.41	1.38	13.36	14.01	10.65	0.93	1.58
2019	7.91	3.41	1.41	13.47	14.12	10.77	0.94	1.60
2020	7.97	3.41	1.43	13.58	14.23	10.91	0.95	1.82
2021	8.01	3.41	1.46	13.67	14.33	11.02	0.95	1.92
2022	8.06	3.41	1.49	13.76	14.41	11.13	0.96	1.97
2023	8.10	3.41	1.51	13.84	14.49	11.21	0.96	2.01
2024	8.13	3.41	1.54	13.91	14.56	11.28	0.97	2.04
2025	8.16	3.41	1.57	13.97	14.62	11.33	0.97	2.11
2026	8.19	3.41	1.60	14.02	14.67	11.36	0.98	2.18
2027	8.21	3.41	1.62	14.07	14.71	11.38	0.98	2.23
2028	8.23	3.41	1.65	14.11	14.74	11.41	0.99	2.28
2029	8.25	3.41	1.68	14.14	14.77	11.42	0.99	2.32
2030	8.26	3.41	1.71	14.16	14.78	11.46	0.99	2.43
2031	8.27	3.41	1.74	14.17	14.79	11.49	0.99	2.54
2032	8.27	3.41	1.78	14.18	14.80	11.51	1.00	2.64
2033	8.28	3.41	1.81	14.18	14.81	11.53	1.00	2.73
2034	8.28	3.41	1.84	14.19	14.82	11.54	1.00	2.83

4.3 Demand-Side Management Plan

Year	Additional Effect[1] of Demand-Side Management Total Energy Requirements (MWh)	Winter Peak Demand (MW)	Summer Peak Demand (MW)
2014	-56,330		-138
2015	-70,781	-131	-150
2016	-100,897	-139	-161
2017	-133,677	-148	-172
2018	-166,457	-156	-183
2019	-199,236	-164	-194
2020	-199,236	-164	-194
2021	-199,236	-164	-194
2022	-197,275	-164	-194
2023	-192,865	-164	-193
2024	-186,248	-163	-192
2025	-175,687	-162	-190
2026	-165,751	-161	-188
2027	-159,786	-160	-187
2028	-153,211	-159	-186
2029	-146,550	-157	-185
2030	-132,629	-152	-182
2031	-118,322	-147	-180
2032	-105,467	-142	-177
2033	-94,259	-138	-175
2034	-83,051	-134	-172

[1]In order to avoid double-counting, additional effects do not include energy efficiency measures installed prior to 2014, which are assumed to be embedded in the historical data used for modeling purposes. Additional effects do include energy efficiency measures installed from 2014 onward and all demand response regardless of the participant start date.

SECTION 5.0

KEY RESULTS

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Section 5.0
Key Results

5.1 Total Energy Requirements

Year	EKPC Sales to Members (MWh)	EKPC Own Use (MWh)	Transmission Losses (MWh)	Actual Net Total Requirements (MWh)	Gross Total Requirements (MWh)	Additional Demand Side Management (MWh)	Weather-Normalized Net Total Requirements (MWh)
2003	11,190,871	9,123	368,320	11,568,314			11,569,542
2004	11,537,505	9,106	319,186	11,865,797			12,032,530
2005	12,060,461	8,903	458,465	12,527,829			12,410,850
2006	11,892,304	7,568	431,400	12,331,272			12,561,140
2007	12,582,259	7,491	490,617	13,080,367			12,885,901
2008	12,646,147	7,932	294,012	12,948,091			12,849,764
2009	11,981,908	8,247	380,153	12,370,308			12,454,354
2010	12,811,907	8,654	555,731	13,376,292			12,918,009
2011	12,289,090	10,146	367,762	12,666,998			12,612,430
2012	11,943,404	8,811	235,192	12,190,070			12,229,318
2013	12,426,020	8,270	210,300	12,644,590			12,257,369
2014	12,855,119	8,306	438,441		13,301,866	-56,330	13,245,535
2015	12,983,289	8,343	447,542		13,439,174	-70,781	13,368,393
2016	13,197,742	8,379	458,642		13,664,763	-100,897	13,563,866
2017	13,438,057	8,416	469,098		13,915,571	-133,677	13,781,894
2018	13,654,376	8,453	478,365		14,141,194	-166,457	13,974,738
2019	13,851,977	8,489	486,285		14,346,751	-199,236	14,147,514
2020	14,130,274	8,527	497,084		14,635,885	-199,236	14,436,649
2021	14,319,472	8,564	504,657		14,832,693	-199,236	14,633,457
2022	14,518,240	8,601	512,455		15,039,296	-197,275	14,842,021
2023	14,706,794	8,639	520,439		15,235,872	-192,865	15,043,007
2024	14,938,774	8,676	529,126		15,476,576	-186,248	15,290,328
2025	15,144,656	8,714	536,901		15,690,271	-175,687	15,514,584
2026	15,411,443	8,752	553,085		15,973,280	-165,751	15,807,528
2027	15,604,205	8,791	560,451		16,173,447	-159,786	16,013,662
2028	15,817,019	8,829	568,818		16,394,666	-153,211	16,241,455
2029	16,015,460	8,868	576,691		16,601,019	-146,550	16,454,469
2030	16,214,196	8,906	584,329		16,807,431	-132,629	16,674,801
2031	16,407,523	8,945	591,701		17,008,169	-118,322	16,889,846
2032	16,580,105	8,984	598,201		17,187,290	-105,467	17,081,823
2033	16,741,901	9,024	604,161		17,355,086	-94,259	17,260,827
2034	16,909,617	9,063	609,741		17,528,421	-83,051	17,445,370

The "2014 Load Forecast" indicates that, through 2034, net total energy requirements will increase from 13.2 to 17.4 million MWh, an average of 1.4 percent per year.

5.2 Winter Peak Demand

Year	Unadjusted Peak Demand (MW)	Additional Demand-Side Management (MW)	Adjusted Peak Demand (MW)
2003	2,568	-133	2,435
2004	2,610	-123	2,487
2005	2,719	-104	2,615
2006	2,599	-122	2,477
2007	2,840	-91	2,749
2008	3,051	-95	2,956
2009	3,152	-49	3,103
2010	2,868	-138	2,730
2011	2,891	-126	2,765
2012	2,481	-131	2,350
2013	2,597	-96	2,501
2014	3,425	-112	3,313
2015	3,338	-131	3,207
2016	3,378	-139	3,239
2017	3,407	-148	3,259
2018	3,438	-156	3,282
2019	3,466	-164	3,302
2020	3,502	-164	3,338
2021	3,529	-164	3,365
2022	3,554	-164	3,390
2023	3,582	-164	3,418
2024	3,618	-163	3,455
2025	3,650	-162	3,488
2026	3,691	-161	3,530
2027	3,728	-160	3,568
2028	3,769	-159	3,610
2029	3,808	-157	3,651
2030	3,842	-152	3,690
2031	3,883	-147	3,736
2032	3,918	-142	3,776
2033	3,953	-138	3,815
2034	3,989	-134	3,855

The “2014 Load Forecast” indicates that, through 2034, the net winter peak demand will increase from 3,207 to 3,855 MW, an average of 1.0 percent per year.

Because the winter peak demand is forecast to grow less quickly than total energy requirements, the winter peak demand-based load factor will increase slightly, from 47.6 percent in 2015 to 51.7 percent by 2034. Because the EKPC system remains winter-peaking throughout the forecast period, this also represents EKPC’s annual load factor.

5.3 Summer Peak Demand

Year	Unadjusted Peak Demand (MW)	Additional Demand-Side Management (MW)	Adjusted Peak Demand (MW)
2003	1,996	-151	1,845
2004	2,052	-104	1,948
2005	2,220	-10	2,210
2006	2,332	-144	2,188
2007	2,481	-135	2,346
2008	2,243	-149	2,094
2009	2,195	-114	2,081
2010	2,443	-146	2,297
2011	2,388	-122	2,266
2012	2,354	-94	2,260
2013	2,199	-104	2,095
2014	2,439	-138	2,302
2015	2,484	-150	2,334
2016	2,524	-161	2,363
2017	2,568	-172	2,396
2018	2,611	-183	2,428
2019	2,650	-194	2,456
2020	2,696	-194	2,502
2021	2,735	-194	2,541
2022	2,775	-194	2,581
2023	2,812	-193	2,619
2024	2,857	-192	2,665
2025	2,897	-190	2,707
2026	2,950	-188	2,762
2027	2,988	-187	2,801
2028	3,031	-186	2,845
2029	3,070	-185	2,885
2030	3,109	-182	2,927
2031	3,148	-180	2,968
2032	3,181	-177	3,004
2033	3,213	-175	3,038
2034	3,247	-172	3,075

The "2014 Load Forecast" indicates that, through 2034, the net summer peak demand will increase from 2,302 to 3,075 MW, an average of 1.5 percent per year.

Because the summer peak demand is forecast to grow at roughly the same rate as the total energy requirements, the summer peak demand-based load factor will remain flat at 65 percent through 2034.

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SECTION 6.0

RESULTS BY CONSUMER CLASS

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Section 6.0
Results by Consumer Class

6.1 Residential

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	441,636	10,469	2.4%	1,171	-21	-1.8%	6,205,364	38,835	0.6%	58.1
2004	451,117	9,481	2.1%	1,171	0	0.0%	6,337,737	132,373	2.1%	57.5
2005	456,103	4,986	1.1%	1,234	63	5.4%	6,751,545	413,808	6.5%	58.5
2006	465,784	9,681	2.1%	1,171	-62	-5.1%	6,545,584	-205,961	-3.1%	57.3
2007	471,584	5,800	1.2%	1,237	66	5.6%	6,998,555	452,971	6.9%	58.2
2008	479,039	7,455	1.6%	1,227	-9	-0.8%	7,055,278	56,723	0.8%	58.5
2009	480,527	1,488	0.3%	1,177	-50	-4.1%	6,789,142	-266,136	-3.8%	59.2
2010	481,868	1,341	0.3%	1,278	100	8.5%	7,388,899	599,757	8.8%	60.4
2011	482,351	483	0.1%	1,204	-74	-5.8%	6,967,415	-421,484	-5.7%	59.0
2012	487,769	5,418	1.1%	1,123	-81	-6.7%	6,572,947	-394,468	-5.7%	57.6
2013	489,630	1,861	0.4%	1,175	52	4.7%	6,905,017	332,070	5.1%	58.1
2014	492,071	2,441	0.5%	1,218	42	3.6%	7,190,266	285,249	4.1%	58.5
2015	495,084	3,013	0.6%	1,198	-20	-1.6%	7,116,809	-73,457	-1.0%	57.3
2016	498,597	3,513	0.7%	1,203	5	0.4%	7,199,040	82,231	1.2%	57.0
2017	502,594	3,997	0.8%	1,208	4	0.4%	7,283,342	84,302	1.2%	56.7
2018	506,924	4,330	0.9%	1,211	3	0.3%	7,367,004	83,662	1.1%	56.4
2019	511,581	4,657	0.9%	1,214	3	0.3%	7,455,700	88,696	1.2%	56.3
2020	516,467	4,886	1.0%	1,218	3	0.3%	7,545,866	90,166	1.2%	55.9
2021	521,337	4,870	0.9%	1,220	3	0.2%	7,634,550	88,684	1.2%	55.8
2022	526,404	5,067	1.0%	1,223	3	0.2%	7,725,997	91,447	1.2%	55.7
2023	531,235	4,831	0.9%	1,226	3	0.3%	7,817,409	91,412	1.2%	55.6
2024	536,435	5,200	1.0%	1,229	3	0.3%	7,914,171	96,762	1.2%	55.4
2025	541,888	5,453	1.0%	1,232	3	0.2%	8,014,115	99,944	1.3%	55.4
2026	547,199	5,311	1.0%	1,235	3	0.2%	8,110,072	95,957	1.2%	55.1
2027	552,278	5,079	0.9%	1,238	2	0.2%	8,201,757	91,685	1.1%	55.0
2028	557,219	4,941	0.9%	1,240	2	0.2%	8,291,671	89,914	1.1%	54.9
2029	561,948	4,729	0.8%	1,242	2	0.2%	8,376,465	84,794	1.0%	54.7
2030	566,362	4,414	0.8%	1,244	2	0.2%	8,455,665	79,200	0.9%	54.6
2031	570,502	4,140	0.7%	1,246	2	0.2%	8,531,239	75,574	0.9%	54.4
2032	574,626	4,124	0.7%	1,248	2	0.2%	8,607,158	75,919	0.9%	54.3
2033	578,576	3,950	0.7%	1,251	2	0.2%	8,683,263	76,105	0.9%	54.3
2034	582,440	3,864	0.7%	1,253	2	0.2%	8,756,724	73,461	0.8%	54.2

6.2 Residential Seasonal

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	4,046	90	2.3	277	-20	-6.6	13,445	-631	-4.5	0.1
2004	4,162	116	2.9	277	0	0.1	13,846	402	3.0	0.1
2005	4,297	135	3.2	281	4	1.4	14,501	655	4.7	0.1
2006	4,371	74	1.7	265	-17	-5.9	13,882	-619	-4.3	0.1
2007	4,459	88	2.0	274	10	3.7	14,679	797	5.7	0.1
2008	4,463	4	0.1	271	-3	-1.1	14,531	-149	-1.0	0.1
2009	4,420	-43	-1.0	247	-25	-9.1	13,080	-1,451	-10.0	0.1
2010	4,490	70	1.6	259	12	5.1	13,959	879	6.7	0.1
2011	4,518	28	0.6	236	-23	-9.1	12,774	-1,185	-8.5	0.1
2012	67	-4,451	-98.5	282	47	19.8	227	-12,547	-98.2	0.0
2013	94	27	40.3	266	-16	-5.8	300	73	32.2	0.0
2014	95	1	1.0	289	23	8.7	329	29	9.8	0.0
2015	96	1	1.5	275	-14	-4.9	318	-11	-3.5	0.0
2016	98	1	1.4	276	1	0.3	323	6	1.7	0.0
2017	99	1	1.4	277	1	0.3	329	5	1.7	0.0
2018	100	1	1.4	277	1	0.3	334	5	1.7	0.0
2019	102	1	1.4	278	1	0.3	340	6	1.7	0.0
2020	103	1	1.5	279	1	0.3	346	6	1.8	0.0
2021	105	2	1.5	280	1	0.3	352	6	1.8	0.0
2022	106	2	1.5	281	1	0.3	359	6	1.8	0.0
2023	108	2	1.5	282	1	0.3	365	6	1.8	0.0
2024	110	2	1.5	282	1	0.3	371	6	1.7	0.0
2025	111	2	1.4	283	1	0.3	378	6	1.7	0.0
2026	113	1	1.3	284	1	0.2	383	6	1.5	0.0
2027	114	1	1.1	285	1	0.2	389	5	1.3	0.0
2028	115	1	1.1	285	1	0.2	393	5	1.3	0.0
2029	116	1	0.9	286	0	0.2	398	4	1.1	0.0
2030	117	1	0.9	286	0	0.2	402	4	1.1	0.0
2031	118	1	0.9	286	0	0.2	406	4	1.0	0.0
2032	119	1	0.9	287	0	0.1	410	4	1.0	0.0
2033	120	1	0.9	287	0	0.1	414	4	1.0	0.0
2034	121	1	0.9	288	0	0.1	419	4	1.0	0.0

Note: In 2012, one member system ceased reporting residential seasonal customers.

6.3 Commercial and Industrial ≤ 1000 KVA

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	26,664	-412	-1.5%	58	0	0.3%	1,550,251	-27,339	-1.7%	14.5
2004	28,122	1,458	5.5%	57	-1	-2.3%	1,597,841	47,590	3.1%	14.5
2005	30,608	2,486	8.8%	57	0	-0.6%	1,729,486	131,645	8.2%	15.0
2006	30,200	-408	-1.3%	59	2	4.2%	1,777,896	48,410	2.8%	15.6
2007	30,981	781	2.6%	60	1	2.1%	1,861,951	84,055	4.7%	15.5
2008	32,035	1,054	3.4%	58	-2	-2.7%	1,872,811	10,860	0.6%	15.5
2009	32,381	346	1.1%	55	-3	-5.6%	1,787,113	-85,698	-4.6%	15.6
2010	32,505	124	0.4%	60	4	7.9%	1,935,184	148,071	8.3%	15.8
2011	32,654	149	0.5%	58	-2	-2.7%	1,892,091	-43,093	-2.2%	15.9
2012	33,047	393	1.2%	57	-1	-1.7%	1,883,243	-8,848	-0.5%	16.5
2013	33,292	245	0.7%	58	1	1.1%	1,917,729	34,486	1.8%	16.1
2014	33,696	404	1.2%	59	1	2.2%	1,984,326	66,597	3.5%	16.1
2015	34,030	334	1.0%	59	0	-0.4%	1,996,862	12,536	0.6%	16.1
2016	34,466	436	1.3%	59	0	0.8%	2,038,435	41,573	2.1%	16.1
2017	34,931	465	1.3%	60	0	0.7%	2,080,437	42,002	2.1%	16.2
2018	35,434	503	1.4%	60	0	0.6%	2,123,865	43,428	2.1%	16.2
2019	35,925	491	1.4%	60	0	0.7%	2,168,939	45,074	2.1%	16.3
2020	36,435	510	1.4%	61	0	0.7%	2,214,180	45,241	2.1%	16.3
2021	36,946	511	1.4%	61	0	0.6%	2,258,394	44,214	2.0%	16.5
2022	37,469	523	1.4%	61	0	0.6%	2,303,360	44,966	2.0%	16.6
2023	37,986	517	1.4%	62	0	0.6%	2,349,882	46,522	2.0%	16.7
2024	38,514	528	1.4%	62	0	0.7%	2,398,920	49,038	2.1%	16.8
2025	39,048	534	1.4%	63	0	0.6%	2,447,930	49,010	2.0%	16.9
2026	39,557	509	1.3%	63	0	0.7%	2,496,649	48,719	2.0%	16.9
2027	40,042	485	1.2%	63	0	0.6%	2,542,048	45,399	1.8%	17.0
2028	40,486	444	1.1%	64	0	0.6%	2,585,118	43,070	1.7%	17.0
2029	40,923	437	1.1%	64	0	0.6%	2,627,461	42,343	1.6%	17.1
2030	41,310	387	0.9%	65	0	0.6%	2,668,568	41,107	1.6%	17.2
2031	41,691	381	0.9%	65	0	0.5%	2,705,463	36,895	1.4%	17.2
2032	42,074	383	0.9%	65	0	0.4%	2,740,772	35,309	1.3%	17.2
2033	42,439	365	0.9%	65	0	0.4%	2,775,905	35,133	1.3%	17.3
2034	42,792	353	0.8%	66	0	0.4%	2,811,172	35,267	1.3%	17.3

6.4 Commercial and Industrial > 1000 KVA

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	134	22	19.6%	21,506	-3,376	-13.6%	2,881,781	94,969	3.4%	27.0
2004	138	4	3.0%	21,973	467	2.2%	3,032,313	150,532	5.2%	27.6
2005	139	1	0.7%	21,709	-264	-1.2%	3,017,603	-14,710	-0.5%	26.1
2006	135	-4	-2.9%	22,646	936	4.3%	3,057,184	39,581	1.3%	26.8
2007	122	-13	-9.6%	25,607	2,961	13.1%	3,124,042	66,858	2.2%	26.0
2008	132	10	8.2%	23,361	-2,246	-8.8%	3,083,590	-40,452	-1.3%	25.1
2009	138	6	4.5%	20,521	-2,839	-12.2%	2,831,936	-251,654	-8.2%	24.7
2010	125	-13	-9.4%	22,767	2,246	10.9%	2,845,857	13,921	0.5%	23.3
2011	127	2	1.6%	22,749	-18	-0.1%	2,889,143	43,286	1.5%	24.6
2012	130	3	2.4%	22,321	-428	-1.9%	2,901,689	12,546	0.4%	25.4
2013	135	5	3.8%	22,355	34	0.2%	3,017,925	116,236	4.0%	25.4
2014	128	-7	-5.2%	23,967	1,612	7.2%	3,067,731	49,806	1.7%	25.0
2015	133	5	3.9%	24,489	523	2.2%	3,257,080	189,349	6.2%	26.2
2016	135	2	1.5%	24,723	234	1.0%	3,337,584	80,504	2.5%	26.4
2017	140	5	3.7%	24,573	-150	-0.6%	3,440,200	102,616	3.1%	26.8
2018	143	3	2.1%	24,610	37	0.2%	3,519,215	79,015	2.3%	26.9
2019	144	1	0.7%	24,817	207	0.8%	3,573,690	54,475	1.5%	27.0
2020	145	1	0.7%	25,535	718	2.9%	3,702,565	128,875	3.6%	27.4
2021	146	1	0.7%	25,684	149	0.6%	3,749,885	47,320	1.3%	27.4
2022	147	1	0.7%	25,870	186	0.7%	3,802,950	53,065	1.4%	27.4
2023	147	0	0.0%	26,155	285	1.1%	3,844,856	41,906	1.1%	27.3
2024	150	3	2.0%	26,138	-17	-0.1%	3,920,737	75,881	2.0%	27.4
2025	150	0	0.0%	26,454	316	1.2%	3,968,149	47,412	1.2%	27.4
2026	156	6	4.0%	26,142	-313	-1.2%	4,078,084	109,935	2.8%	27.7
2027	156	0	0.0%	26,442	300	1.1%	4,124,892	46,808	1.1%	27.6
2028	158	2	1.3%	26,551	110	0.4%	4,195,083	70,191	1.7%	27.7
2029	160	2	1.3%	26,608	57	0.2%	4,257,257	62,174	1.5%	27.8
2030	162	2	1.3%	26,707	99	0.4%	4,326,460	69,203	1.6%	27.9
2031	165	3	1.9%	26,659	-47	-0.2%	4,398,760	72,300	1.7%	28.0
2032	166	1	0.6%	26,821	162	0.6%	4,452,229	53,469	1.2%	28.1
2033	166	0	0.0%	27,082	261	1.0%	4,495,577	43,348	1.0%	28.1
2034	167	1	0.6%	27,228	146	0.5%	4,547,095	51,518	1.1%	28.1

6.5 Public Street and Highway Lighting

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Annual Average (MWh)	Change (MWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	366	13	3.7%	20	0	1.1%	7,448	341	4.8%	0.1
2004	377	11	3.0%	20	0	-2.3%	7,497	49	0.7%	0.1
2005	390	13	3.4%	20	0	-0.5%	7,714	217	2.9%	0.1
2006	420	30	7.7%	20	0	-0.9%	8,235	521	6.8%	0.1
2007	434	14	3.3%	19	0	-0.6%	8,459	224	2.7%	0.1
2008	441	7	1.6%	21	2	10.2%	9,476	1,017	12.0%	0.1
2009	425	-16	-3.6%	21	0	-0.7%	9,067	-409	-4.3%	0.1
2010	423	-2	-0.5%	22	1	5.3%	9,505	438	4.8%	0.1
2011	416	-7	-1.7%	24	1	5.3%	9,846	341	3.6%	0.1
2012	414	-2	-0.5%	23	0	-2.0%	9,601	-245	-2.5%	0.1
2013	412	-2	-0.5%	24	1	3.0%	9,845	244	2.5%	0.1
2014	418	6	1.5%	24	0	-0.4%	9,952	107	1.1%	0.1
2015	427	9	2.2%	24	0	-0.8%	10,086	134	1.3%	0.1
2016	431	4	0.9%	24	0	0.5%	10,234	148	1.5%	0.1
2017	438	7	1.6%	24	0	-0.1%	10,387	153	1.5%	0.1
2018	441	3	0.7%	24	0	0.8%	10,540	153	1.5%	0.1
2019	446	5	1.1%	24	0	0.4%	10,698	158	1.5%	0.1
2020	451	5	1.1%	24	0	0.4%	10,856	158	1.5%	0.1
2021	456	5	1.1%	24	0	0.3%	11,014	158	1.5%	0.1
2022	463	7	1.5%	24	0	-0.1%	11,172	158	1.4%	0.1
2023	470	7	1.5%	24	0	-0.1%	11,330	158	1.4%	0.1
2024	475	5	1.1%	24	0	0.3%	11,486	156	1.4%	0.1
2025	480	5	1.1%	24	0	0.3%	11,647	161	1.4%	0.1
2026	484	4	0.8%	24	0	0.5%	11,802	155	1.3%	0.1
2027	487	3	0.6%	25	0	0.6%	11,944	142	1.2%	0.1
2028	493	6	1.2%	24	0	-0.1%	12,078	134	1.1%	0.1
2029	496	3	0.6%	25	0	0.4%	12,203	125	1.0%	0.1
2030	499	3	0.6%	25	0	0.4%	12,326	123	1.0%	0.1
2031	503	4	0.8%	25	0	0.1%	12,438	112	0.9%	0.1
2032	505	2	0.4%	25	0	0.5%	12,547	109	0.9%	0.1
2033	510	5	1.0%	25	0	-0.2%	12,643	96	0.8%	0.1
2034	514	4	0.8%	25	0	-0.1%	12,733	90	0.7%	0.1

6.6 Other Public Authorities

	Consumers			Use Per Consumer			Class Sales			
	Annual Average	Annual Change	Percent Change	Monthly Average (kWh)	Change (kWh)	Percent Change	Total (MWh)	Annual Change (MWh)	Percent Change	Percent of Total Sales
2003	907	18	2.0%	1,999	81	4.3%	21,753	1,301	6.4%	0.2
2004	916	9	1.0%	2,090	91	4.6%	22,974	1,221	5.6%	0.2
2005	910	-6	-0.7%	2,063	-27	-1.3%	22,530	-444	-1.9%	0.2
2006	931	21	2.3%	1,987	-76	-3.7%	22,196	-334	-1.5%	0.2
2007	969	38	4.1%	2,273	286	14.4%	26,426	4,230	19.1%	0.2
2008	993	24	2.5%	2,860	587	25.8%	34,074	7,648	28.9%	0.3
2009	998	5	0.5%	2,965	105	3.7%	35,507	1,433	4.2%	0.3
2010	1,047	49	4.9%	3,168	204	6.9%	39,809	4,302	12.1%	0.3
2011	1,084	37	3.5%	2,957	-211	-6.7%	38,468	-1,341	-3.4%	0.3
2012	1,096	12	1.1%	2,676	-281	-9.5%	35,194	-3,274	-8.5%	0.3
2013	1,109	13	1.2%	2,796	120	4.5%	37,215	2,021	5.7%	0.3
2014	1,111	2	0.2%	2,851	55	1.9%	38,009	794	2.1%	0.3
2015	1,116	5	0.5%	2,827	-24	-0.8%	37,860	-149	-0.4%	0.3
2016	1,124	8	0.7%	2,875	48	1.7%	38,778	918	2.4%	0.3
2017	1,133	9	0.8%	2,902	27	0.9%	39,451	673	1.7%	0.3
2018	1,142	9	0.8%	2,909	7	0.2%	39,862	411	1.0%	0.3
2019	1,153	11	1.0%	2,926	17	0.6%	40,486	624	1.6%	0.3
2020	1,164	11	1.0%	2,953	27	0.9%	41,243	757	1.9%	0.3
2021	1,177	13	1.1%	2,960	7	0.2%	41,806	563	1.4%	0.3
2022	1,188	11	0.9%	2,961	1	0.0%	42,206	400	1.0%	0.3
2023	1,201	13	1.1%	2,956	-5	-0.2%	42,599	393	0.9%	0.3
2024	1,213	12	1.0%	2,950	-6	-0.2%	42,941	342	0.8%	0.3
2025	1,225	12	1.0%	2,943	-7	-0.2%	43,263	322	0.7%	0.3
2026	1,237	12	1.0%	2,937	-6	-0.2%	43,591	328	0.8%	0.3
2027	1,247	10	0.8%	2,936	-1	0.0%	43,929	338	0.8%	0.3
2028	1,259	12	1.0%	2,931	-5	-0.2%	44,279	350	0.8%	0.3
2029	1,268	9	0.7%	2,933	2	0.1%	44,631	352	0.8%	0.3
2030	1,278	10	0.8%	2,931	-2	-0.1%	44,956	325	0.7%	0.3
2031	1,284	6	0.5%	2,936	4	0.2%	45,236	280	0.6%	0.3
2032	1,291	7	0.5%	2,936	0	0.0%	45,489	253	0.6%	0.3
2033	1,296	5	0.4%	2,940	4	0.1%	45,730	241	0.5%	0.3
2034	1,302	6	0.5%	2,942	2	0.1%	45,972	242	0.5%	0.3

SECTION 7.0

RESULTS BY ECONOMIC AND WEATHER SCENARIO

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Section 7.0
Results by Economic and Weather Scenario

7.1 Peak Demand and Scenario Results

In addition to the forecasted peaks, high and low cases are developed. The same methodology is used, however, the starting summary file is different. Instead of using the sum of the member system files, two new models are built: one reflecting assumptions that result in optimistic economic growth and extreme weather conditions and one reflecting pessimistic economic growth and mild weather conditions. The assumptions that are varied include:

1. Weather: based on historical heating and cooling degree day data, alternate weather projections were developed based upon the 90th and 10th percentile to reflect extreme and mild weather, respectively. The resulting forecasts reflect cases assuming base case annual degree days +/-20%.

2. Electric price: The general approach is to use price forecasts that are available and use the growth rates from those forecasts to prepare the high and low growth rates around the growth patterns for the base case residential price forecast.

   Therefore, the high scenario for the residential price forecast is constructed to have a 3.2% compound annual growth rate, while the low scenario is constructed to have a 1.6% compound annual growth rate. The adjustments to growth rate are applied to the base case on an annual basis.

3. Residential customers: In the EKPC base case load forecast for 2014 through 2034, the projected number of residential customers increases at a growth rate of 0.9%. The basic approach to preparing high and low case scenarios for the future number of residential customers is to determine the magnitude of variation in the past between long term average growth rates and higher or lower growth rates during shorter periods of time.

   These resulting adjustments were applied to the 20 year compound annual growth rate in the base case customer count forecast resulting in a high customer case of 1.6% growth rate and 0.3% for the low case growth rate. This relationship was preserved in preparing the monthly customer counts for the high and low case scenarios.

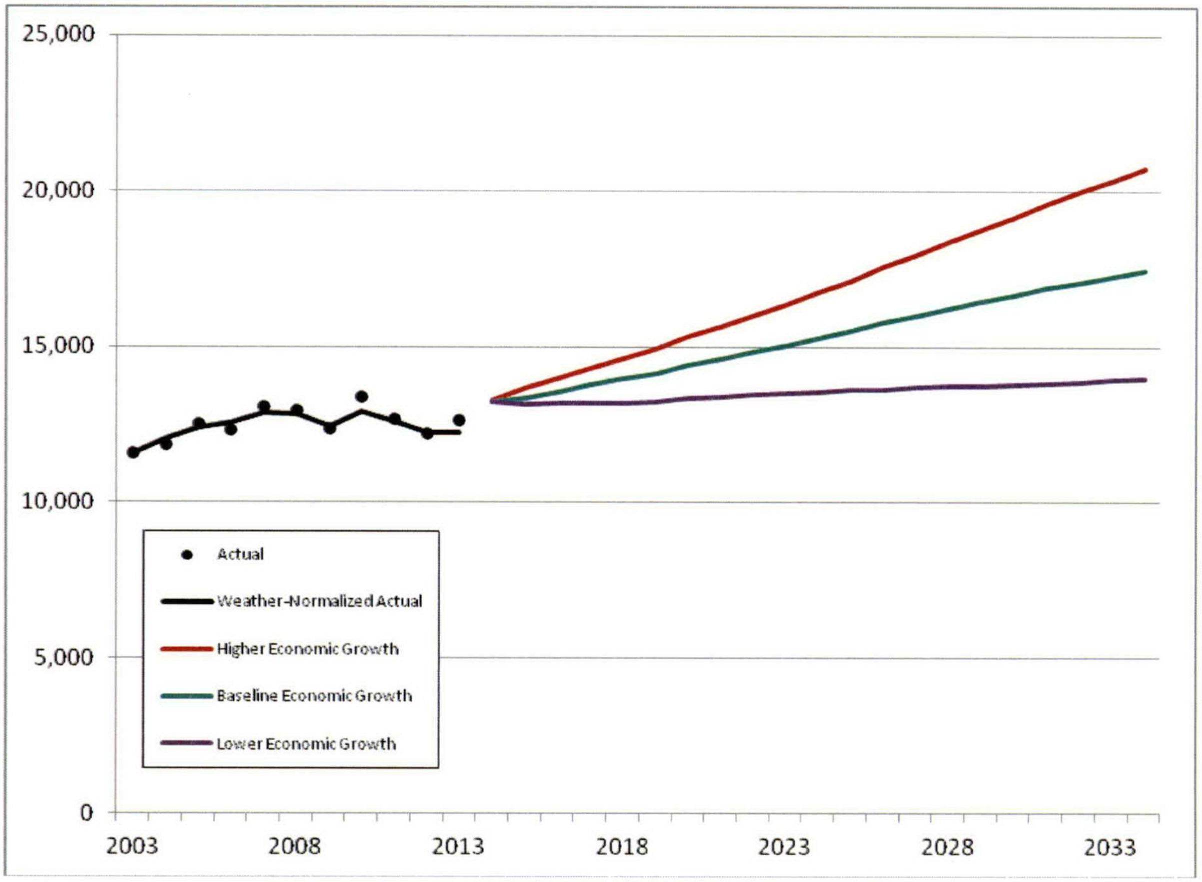
4. Small and Large Commercial customer and energy – Small commercial customer growth is correlated to residential customer growth and the relationship was maintained when developing the high and low cases. Therefore, based upon the resulting high and low residential customer

forecasts, the small commercial customers were impacted accordingly. For the large class, given year to year customer change is small, the low case was based upon no new customers for the forecast period. The high case was based on adding one new customer per year. For energy, small and large commercial usage is not as weather sensitive as residential usage, however, price does impact usage. Therefore, the low case assumes the higher prices while the high case assumes the lower prices.

Adjusting these assumptions leads to different customer forecasts which in turn results in different energy forecasts. The following cases were developed:

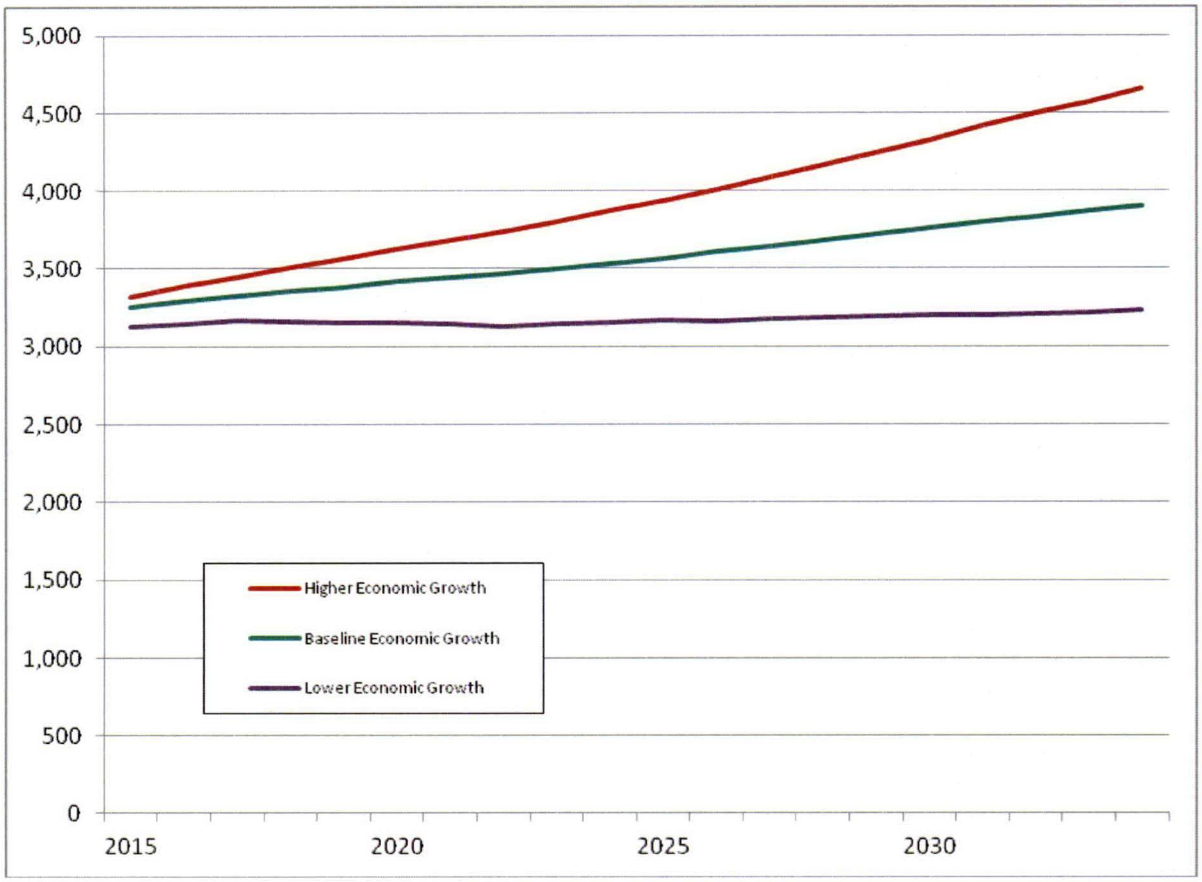
Low Case - Pessimistic economic assumptions with mild weather causing lower loads
Base Case - Most probable economics assumptions with normal weather (Base Case pre DSM)
High Case - Optimistic economic assumptions with severe weather causing higher loads.

7.1.1 Net Total Energy Requirements (MWh) by Economic and Weather Scenario



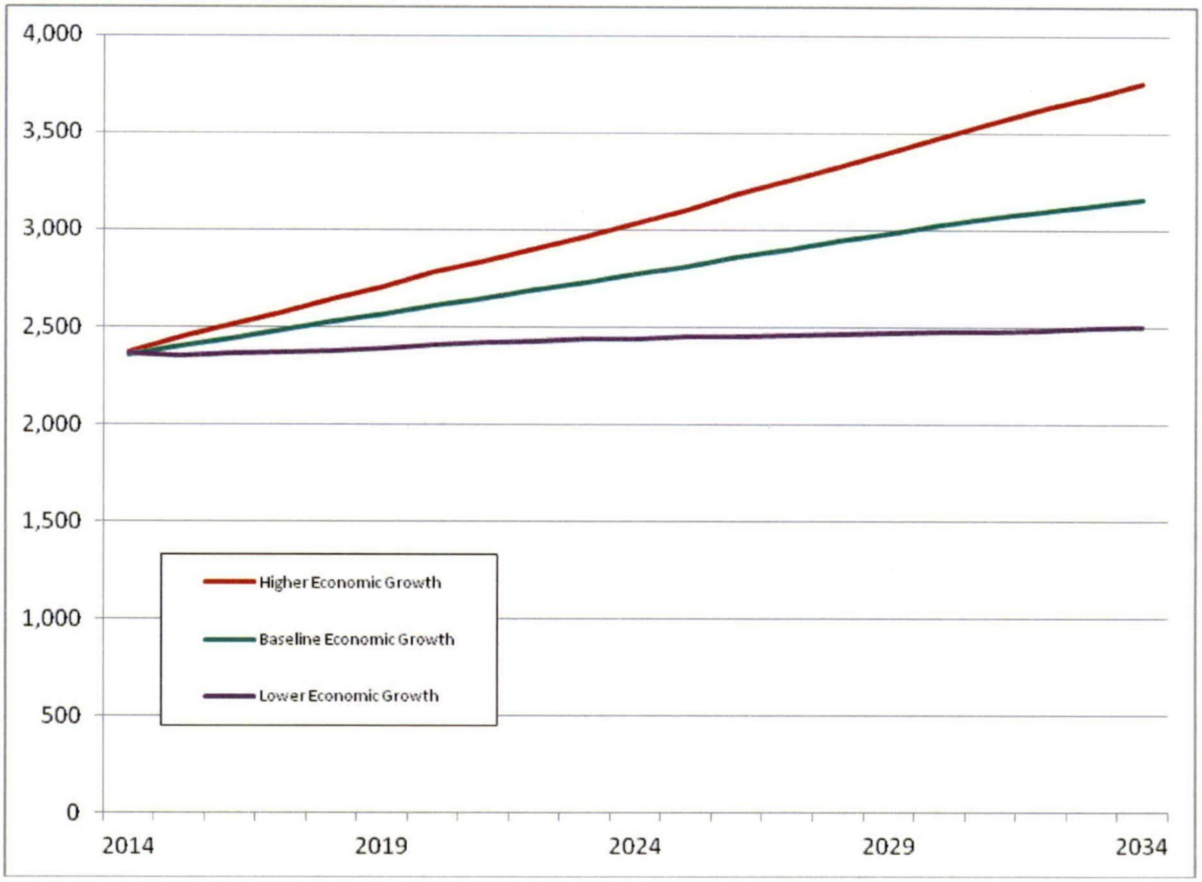
The higher economic growth scenario begins 0.1 and ends 19.0 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins 0.1 and ends 19.8 percent less than the baseline economic growth scenario.

7.1.2 Net Winter Peak Demand (MW) by Economic and Weather Scenario



The higher economic growth scenario begins 2.0 and ends 19.1 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins 3.9 and ends 17.3 percent less than the baseline economic growth scenario.

7.1.3 Net Summer Peak Demand (MW) by Economic and Weather Scenario



The higher economic growth scenario begins 0.6 and ends 18.7 percent greater than the baseline economic growth scenario. The lower economic growth scenario begins roughly equal to and ends 20.8 percent less than the baseline economic growth scenario.

7.2 Peak Demands and Total Requirements (Pre-DSM)

Impacts due to interruptible contracts have been subtracted.

Total Winter Peak Demand (MW)				Total Summer Peak Demand (MW)				Total Requirements (MWh)			
Season	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case	Year	Low Case	Base Case	High Case
2013-2014*		3,341		2014	2,364	**2,355**	2,368	2014	13,243,791	**13,245,535**	13,261,336
2014-2015	3,127	**3,254**	3,318	2015	2,350	**2,400**	2,444	2015	13,151,597	**13,368,393**	13,659,065
2015-2016	3,146	**3,294**	3,387	2016	2,364	**2,440**	2,507	2016	13,201,297	**13,563,866**	13,971,740
2016-2017	3,170	**3,323**	3,443	2017	2,369	**2,484**	2,575	2017	13,196,430	**13,781,894**	14,303,995
2017-2018	3,157	**3,354**	3,506	2018	2,376	**2,527**	2,641	2018	13,205,184	**13,974,738**	14,628,946
2018-2019	3,150	**3,382**	3,565	2019	2,387	**2,566**	2,703	2019	13,234,562	**14,147,514**	14,929,298
2019-2020	3,150	**3,418**	3,627	2020	2,410	**2,612**	2,778	2020	13,363,207	**14,436,649**	15,334,499
2020-2021	3,142	**3,445**	3,682	2021	2,418	**2,651**	2,837	2021	13,407,741	**14,633,457**	15,654,837
2021-2022	3,130	**3,470**	3,738	2022	2,426	**2,691**	2,901	2022	13,456,119	**14,842,021**	16,000,969
2022-2023	3,146	**3,498**	3,800	2023	2,438	**2,728**	2,964	2023	13,526,293	**15,043,007**	16,350,037
2023-2024	3,151	**3,534**	3,869	2024	2,442	**2,773**	3,036	2024	13,556,076	**15,290,328**	16,743,525
2024-2025	3,166	**3,566**	3,933	2025	2,454	**2,813**	3,103	2025	13,630,755	**15,514,584**	17,116,385
2025-2026	3,161	**3,607**	4,009	2026	2,450	**2,866**	3,184	2026	13,622,873	**15,807,528**	17,568,379
2026-2027	3,175	**3,644**	4,084	2027	2,461	**2,904**	3,252	2027	13,687,464	**16,013,662**	17,943,843
2027-2028	3,183	**3,685**	4,165	2028	2,467	**2,947**	3,326	2028	13,726,483	**16,241,455**	18,349,186
2028-2029	3,188	**3,724**	4,246	2029	2,471	**2,986**	3,399	2029	13,757,899	**16,454,469**	18,752,071
2029-2030	3,196	**3,758**	4,325	2030	2,477	**3,025**	3,474	2030	13,802,036	**16,674,801**	19,176,600
2030-2031	3,198	**3,799**	4,414	2031	2,479	**3,064**	3,551	2031	13,825,076	**16,889,846**	19,606,095
2031-2032	3,207	**3,834**	4,492	2032	2,485	**3,097**	3,620	2032	13,871,863	**17,081,823**	19,995,481
2032-2033	3,218	**3,869**	4,568	2033	2,494	**3,129**	3,684	2033	13,929,392	**17,260,827**	20,355,243
2033-2034	3,230	**3,905**	4,651	2034	2,504	**3,163**	3,755	2034	13,992,475	**17,445,370**	20,752,409

*Note: 2013-2014 Winter is an actual peak.

Exhibit LF-1

Price Elasticity Study

1 Introduction

East Kentucky Power Cooperative, Inc. ("EKPC") filed an Integrated Resource Plan ("IRP") with the Kentucky Public Service Commission ("KPSC") on April 23. 2012[1]. The KPSC Staff filed a report titled "Staff Report on the 2012 Integrated Resource Plan of East Kentucky Power Cooperative, Inc. ", on September 2013. In its report, Staff recommended that "EKPC should discuss and report separately the impact on demand and energy forecasts of any projected increases in the price of electricity to its ultimate customers in its next IRP. The price elasticity of the demand for electricity should be fully examined and discussed, and a sensitivity analysis should be performed."

2 Study Objective

EKPC engaged GDS Associates, Inc. ("GDS") to conduct an independent study to estimate price elasticity of demand from primary source data to allow EKPC forecasters to verify and refine the elasticity assumptions that have been assumed for previous planning analyses, and to provide a basis for elasticity assumptions used in future load forecasts. Additionally, in efforts to provide support for EKPC's analysis, the study entailed conducting secondary research to identify price elasticity study results conducted by other electric utilities and research firms. In response to the recommendation made by Staff, this report presents the estimated impact of potential increases in the price of electricity to EKPC's ultimate customers. Additionally, results of the study provide the input necessary to conduct sensitivity analysis in EKPC's next load forecast and IRP.

3 Methodology

Econometric modeling was used to perform the price elasticity analysis. Multiple model specifications were investigated to help provide a reasonable range of elasticity estimates. Models were developed at the aggregate EKPC level by customer class and at the member distribution cooperative level by class. All models were analyzed using data on an annual and monthly basis. GDS developed the methodology, conducted the analysis, and reviewed the methodology and results with EKPC staff prior to publishing this report.

3.1 Data

A database of the components necessary to build econometric models was developed by EKPC and provided to GDS. This section describes the data and sources used for the analysis.

3.1.1 Utility Billing History

Monthly number of customers, kWh sales, and revenues by revenue class (residential, commercial, industrial, street lighting, and public authorities) were compiled for each member cooperative for January 2000 through September 2014.

The residential class represents 93% of the total number of customers served by EKPC's member distribution cooperatives. In 2013, the class represented 58% of total energy sales, totaling 6,900 GWh. Residential energy sales have grown by an average compound rate of 1.6% per year from 2000 through 2013.

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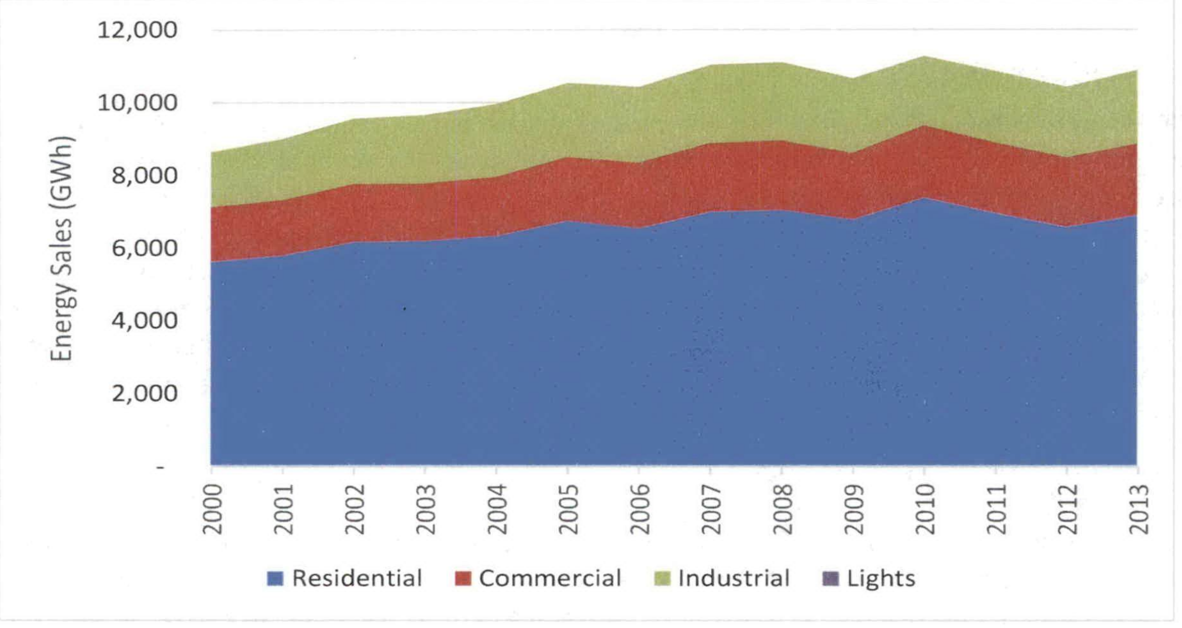
[1] KPSC Case No. 2012-00149

The commercial class, including public authority accounts, represented 7% of EKPC's customers and 18% of energy sales in 2013. In terms of both number of customers and energy sales, the class grew faster than the residential class from 2000 through 2013. Energy sales averaged 2.1% per year in compound growth.

The industrial class consists of less than 150 total accounts, but represented 25% of total energy sales in 2013. Growth in the industrial class has been healthy, averaging 2.2% per year in energy sales growth.

Figure 2.1 – Energy Sales by Class (2000-2013)



3.1.2 Price of Electricity

Nominal price of electricity was computed using the utility billing history. Annual average revenue per kWh was used to represent nominal price each year. The Purchase Consumption Expenditure ("PCE") deflator, provided by Woods & Poole Economics, Inc., was used to compute real price of electricity. The annual real price of electricity was used to represent price in every month for econometric models developed using monthly data.

Table 2.1 – Purchase Consumption Expenditure Deflator (2009=100)

Year	PCE	Year	PCE
2000	83.1	2008	100.1
2001	84.7	2009	100.0
2002	85.9	2010	101.7
2003	87.6	2011	104.1
2004	89.7	2012	106.0
2005	92.3	2013	107.3
2006	94.7	2014	109.4
2007	97.1		

Real residential price has risen by an average of 7% per year from 2000 through 2013. Commercial and industrial prices have risen a little more modestly at 5% per year.

Figure 2.2 – Residential Price (EKPC Total)

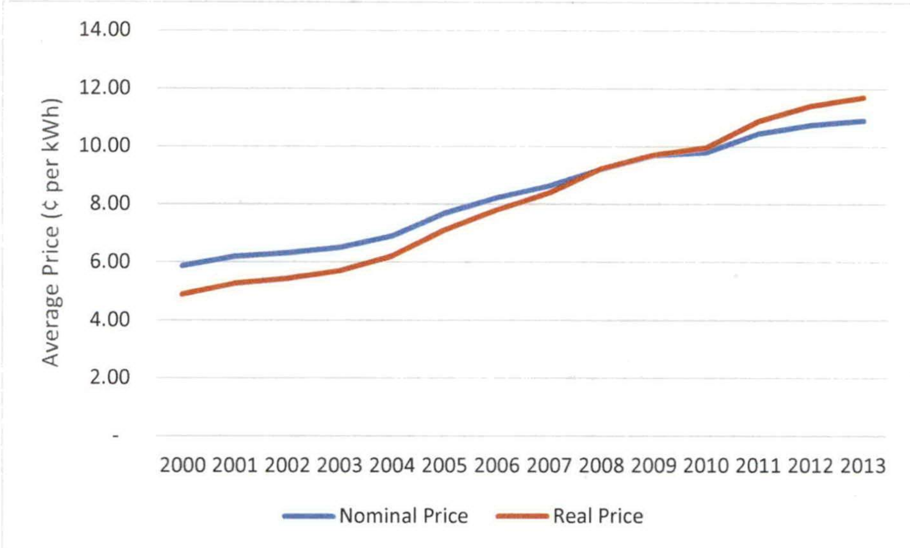
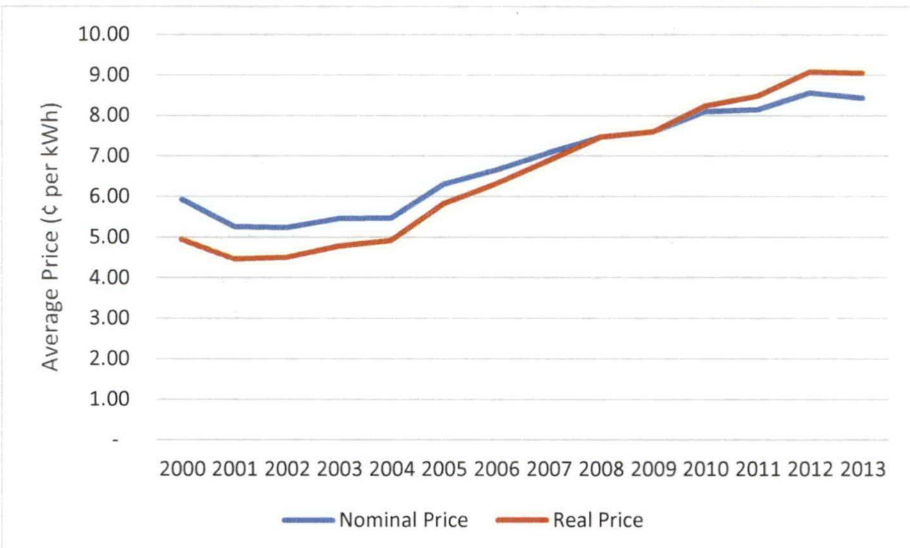


Figure 2.3 – Commercial and Industrial Price (EKPC Total)



3.1.3 Weather Data

Monthly heating degree days ("HDD") and cooling degree days ("CDD") were obtained from the National Oceanic and Atmospheric Association ("NOAA"). Seven weather stations are used to represent local climatological conditions for EKPC's members (see Table 2.2). Due to the fact that reported kWh sales are often based on billing cycle readings and weather data are perfect calendar months, models were tested using actual month weather data, one month lag of weather data, and an average of the current and prior month.

Table 2.2 – Weather Station Assignment

Weather Station	EKPC Member Cooperatives Assigned to Station
Lexington, KY	Blue Grass Energy Cooperative, Clark Energy Cooperative, Inter-County Energy Cooperative
Bowling Green, KY	Farmers RECC, Taylor County RECC
Covington, KY	Fleming-Mason Energy Cooperative, Owen Electric Cooperative
Huntington, WV	Grayson RECC
Jackson, KY	Big Sandy RECC, Cumberland Valley Electric, Jackson Energy Cooperative, Licking Valley RECC
Louisville, KY	Nolin RECC, Salt River Electric Cooperative, Shelby Energy Cooperative
Somerset, KY	South Kentucky RECC

For the EKCP aggregate analyses, weighted average HDD and CDD were computed using class sales assigned to each weather station in each month as the weighting factors.

3.1.4 Economic Data

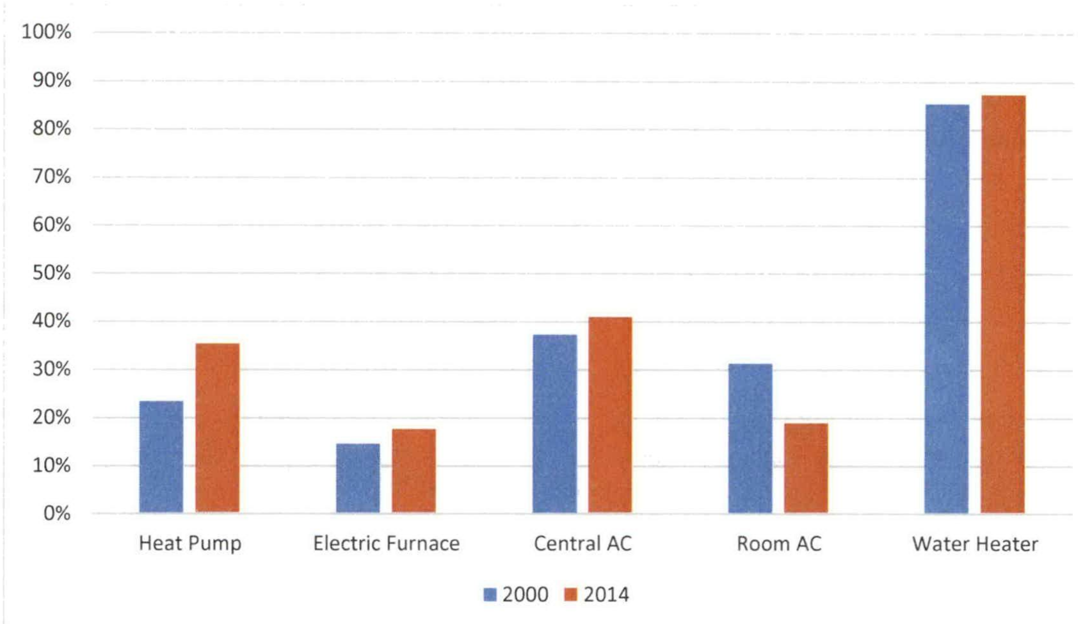
Economic time series data for each member cooperative's service territory was collected from IHS Global Insight[2]. Global Insight draws data from the US Census Bureau, the Bureau of Labor Statistics, and the Bureau of Economic Analysis to develop historical economic time series. For this study, population, real total personal income, and employment were included in the analysis database.

3.1.5 Residential End-Use Appliance Data

Residential electric appliance saturation data was provided to GDS by EKPC staff. The most recent survey was completed in 2013, and surveys have been conducted every two to three years since 1981. EKPC staff interpolated market share information for the intervening years. Appliance efficiency trends over time for major end-use appliances (HVAC equipment and water heaters) were obtained from the Energy Information Administration's ("EIA") Annual Energy Outlook. Appliance saturations are specific to the member service territories. Appliance efficiencies are assumed to be consistent for the entire EKPC territory.

[2] Economic Outlook, March 2014

Figure 2.4 – Residential Electric End-Use Saturations (EKPC Total)



3.2 Econometric Modeling

Several econometric model specifications were designed and tested to evaluate price elasticity of demand. Furthermore, models were developed for the entire EKPC territory in aggregate and for each individual member distribution cooperative. The following sections describe the model designs for the residential and commercial classes. Resultant elasticity estimates produced by these models are provided in Section 3.

3.2.1 Residential Models

Three separate model specifications were tested for the residential price elasticity estimate, one using monthly data and two using annual data. Equations 2.1 through 2.3 show the models tested for aggregate EKPC residential usage. Equations 2.1 and 2.2 were tested for individual member cooperatives.

Equation 2.1

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 PCAPInc_{y,m} + \beta_3 wHDD_{y,m} + \beta_4 wCDD_{y,m} + \varepsilon_{y,m}$$

Equation 2.2

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 PCAPInc_y + \beta_3 wHDD_y + \beta_4 wCDD_y + \varepsilon_y$$

Equation 2.3

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(PCAPInc_y) + \beta_3 Ln(wHDD_y) + \beta_4 Ln(wCDD_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, β_3, and β_4	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
PCAPInc	Per capita income
wHDD	Weighted heating degree days (see further explanation below)
wCDD	Weighted cooling degree days (see further explanation below)
Ln	Natural logarithm
ε	Error term

For some of the individual member models, per capita income had a negative coefficient or had a coefficient with a p-value well in excess of 0.20. A negative coefficient for per capita income is theoretically incorrect, indicating average household energy consumption declines as income increases. In such instances, per capita income was removed from the models.

GDS also tested for first order autocorrelation in the residuals using the Durbin-Watson statistic. In models in which autocorrelation was evident, a first order autoregressive parameter was included in the model to correct for the correlation. This correction helps produce unbiased and more efficient estimators of the coefficients relative to a model with correlated residuals and no autoregressive parameter.

3.2.1.1 Weighted HDD and CDD

For the residential models, HDD and CDD were weighted to take electric appliance market share and efficiency into account. In theory, average usage will be more sensitive to weather as weather-sensitive electric appliances are added to the home (HVAC and water heaters). Likewise, as those appliances become more efficient, average usage will become less sensitive to weather. Therefore, a weighting scheme is developed for the HDD and CDD that effectively multiplies the weather variables by market share (direct relationship) and divides by an index for the change in efficiency over time (indirect relationship). For example, the weights for HDD in January 2000 and January 2014 are shown in table 2.3.

Table 2.3 – Example Development of HDD weights

Line No.	Item	Formula	January 2000	January 2014
[1]	Heat Pump Saturation		0.234	0.351
[2]	Heat Pump Efficiency (HSPF)		6.830	7.550
[3]	Efficiency Index (Sep 2014=1.00)		0.896	0.991
[4]	Heat Pump Weight	[1]÷[3]	0.261	0.354
[5]	Electric Furnace Saturation		0.146	0.175
[6]	Furnace Efficiency		3.410	3.410
[7]	Efficiency Index (Sep 2014=1.00)		1.000	1.000
[8]	Heat Pump Weight	[5]÷[7]	0.146	0.175
[9]	Weight for HDD	[4]+[8]	0.407	0.529

3.2.2 Small Commercial Models – EKPC Aggregate

Three separate model specifications were tested for the aggregate EKPC small commercial price elasticity estimate, one using monthly data and two using annual data. Equations 2.4 through 2.6 show the models tested.

Equation 2.4

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_{y,m} + \beta_3 HDD_{y,m} + \beta_4 CDD_{y,m} + \varepsilon_{y,m}$$

Equation 2.5

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_y + \beta_3 HDD_y + \beta_4 CDD_y + \varepsilon_y$$

Equation 2.6

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(Emp_y) + \beta_3 Ln(HDD_y) + \beta_4 Ln(CDD_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, β_3, and β_4	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
Emp	Employment
HDD	Billing cycle heating degree days
CDD	Billing cycle cooling degree days
Ln	Natural logarithm
ε	Error term

3.2.3 Industrial Models – EKPC Aggregate

Three separate model specifications were tested for the industrial price elasticity estimate for aggregate EKPC industrial sales, one using monthly data and two using annual data. Equations 2.7 through 2.9 show the models tested.

Equation 2.7

$$AvgUse_{y,m} = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_{y,m} + \sum_m \beta_{3,m} I_m + \varepsilon_{y,m}$$

Equation 2.8

$$AvgUse_y = \beta_0 + \beta_1 RealPrice_y + \beta_2 Emp_y + \varepsilon_y$$

Equation 2.9

$$Ln(AvgUse_{y)} = \beta_0 + \beta_1 Ln(RealPrice_y) + \beta_2 Ln(Emp_y) + \varepsilon_y$$

Where:

β_0, β_1, β_2, and $\beta_{3,m}$	Regression coefficients
y	Index for the year
m	Index for the month
AvgUse	Residential average usage (kWh per customer)
RealPrice	Real price of electricity
Emp	Employment
I_m	Indicator variable for month m
Ln	Natural logarithm
ε	Error term

3.2.4 Commercial and Industrial Models by Member Cooperative

Econometric models consistent with Equation 2.4 were run for the combined commercial and industrial classes by member cooperative. As will be discussed further in Section 3, however, it was difficult to produce models for some members that provided theoretically sound results for price elasticity.

4 Results and Conclusions

At the EKPC aggregate level, the multiple econometric specifications produced elasticity estimates that were statistically equivalent at 90% confidence. The residential models by member cooperative produced a wider array of results as might be expected, but all provided a theoretically correct negative price elasticity estimate. The same cannot be said for all C&I models at the member cooperative level.

4.1 Residential Elasticity

The measured overall price elasticity of demand is approximately -0.25, indicating that a 1% increase in real prices will result in a 0.25% decrease in residential average usage per household across the entire EKPC system. Individual member results vary from a low of -0.02 to a high of -0.73. The higher variability in elasticity estimates at the member level is more likely a function of the data than a true significant difference in price response across different territories. Data adjustments, alignment of billing cycles with weather, and other anomalies are more likely to impact results at the member-level, whereas aggregate data will help average out some of that noise in the data and provide a truer estimate of overall price sensitivity.

Table 3.1 – Aggregate EKCP Residential Price Elasticity Estimates

Model Specification	Estimated Price Elasticity
Monthly Model (Equation 2.1)	-0.271
Annual Model (Equation 2.2)	-0.247
Annual Log-Log Model (Equation 2.3)	-0.181

None of the elasticity estimates shown in Table 3.1 can be verified as statistically different from the others at 90% confidence. Three separate modeling approaches providing consistent results supports the conclusion that the estimated elasticity is reasonable.

Table 3.2 – Member Cooperative Residential Price Elasticity Estimates

Member	Monthly Model (Equation 2.1) Price Elasticity Estimate	Annual Model (Equation 2.2) Price Elasticity Estimate
Jackson Energy Cooperative	-0.730	-0.298
Salt River Electric Cooperative	-0.023	-0.131
Taylor County RECC	-0.069	-0.488
Inter-County Energy Coop.	-0.172	-0.124
Shelby Energy Cooperative	-0.049	-0.035
Farmers RECC	-0.260	-0.223
Owen Electric Cooperative	-0.239	-0.062
Clark Energy Cooperative	-0.190	-0.187
Nolin RECC	-0.156	-0.116
Fleming-Mason Energy Coop.	-0.201	-0.287
South Kentucky RECC	-0.232	-0.177
Licking Valley RECC	-0.105	-0.076
Cumberland Valley Electric	-0.333	-0.060
Big Sandy RECC	-0.163	-0.194
Grayson RECC	-0.517	-0.240
Blue Grass Energy Cooperative	-0.128	-0.121
Weighted Average*	***-0.233***	***-0.168***

* Weights based on 2013 residential energy sales.

Given that: a) noise in billing data has more impact at the member level, and b) for some member models, per capita income did not have significance in the model, GDS recommends that EKPC use a consistent price elasticity estimate based on the aggregated model results provided in Table 3.1. **It is concluded that an elasticity in the range of -0.20 and -0.30 would be a reasonable assumption based on the results of this analysis.**

4.2 Commercial and Industrial Elasticity

Commercial and industrial price elasticity estimates are lower than residential. The small commercial class has an elasticity of approximately -0.10 and the industrial class is about -0.05. Smaller commercial accounts might be quite price inelastic due to several factors, including having little control over electricity consumption (for instance a convenience store with many freezers and refrigerator cases), being a tenant that does not pay the electric bill, or having electricity generally be a small proportion of the budget. Furthermore, large commercial and industrial accounts are unlikely to alter operations in response to small changes in price, but there is certainly a point where, if price goes too high or margins are too low for a company, they might stop operation altogether or shut down a shift, causing a large response to price at some certain threshold. It is reasonable to assume that, as a class, commercial customers are less sensitive to long-term price changes than are residential customers.

Table 3.3 – Aggregate EKPC Commercial and Industrial Price Elasticity Estimates

Model Specification	Small Commercial Price Elasticity	Industrial Price Elasticity
Monthly Model (Equations 2.4 and 2.7)	-0.149	-0.102
Annual Model (Equation 2.5 and 2.8)	-0.117	-0.034
Annual Log-Log Model (Equation 2.6 and 2.9)	-0.097	-0.030

At the member distribution cooperative level, several of the models were unable to measure a statistically significant (indicating a likelihood of a zero elasticity) or theoretically correct (negative coefficient) price elasticity. Due to some members having very few industrial accounts, the member-level analysis was conducted for the commercial and industrial customers in aggregate. As with the residential elasticity, GDS would recommend use of a system-wide elasticity estimate for EKPC's load forecasting. An elasticity assumption in the range of -0.05 to -0.15 is for all commercial and industrial customers based on this analysis.

Table 3.4 – Member Cooperative C&I Price Elasticity Estimates

Member	Monthly Model (Equation 2.4) Price Elasticity Estimate
Jackson Energy Cooperative	-0.177
Salt River Electric Cooperative	-0.045
Taylor County RECC	-0.090
Inter-County Energy Coop.	-0.396
Shelby Energy Cooperative	n/a[1]
Farmers RECC	-0.221
Owen Electric Cooperative	-0.285
Clark Energy Cooperative	-0.131
Nolin RECC	-0.473
Fleming-Mason Energy Coop.	-0.067
South Kentucky RECC	n/a[1]
Licking Valley RECC	-0.023
Cumberland Valley Electric	n/a[1]
Big Sandy RECC	-0.175
Grayson RECC	-0.384
Blue Grass Energy Cooperative	-0.094

4.3 Secondary Research

Secondary research included a review of publically available information related to current price elasticity estimates being made by others in the industry. **Results of the review are provided below and confirm that the elasticity estimates derived for EKPC are consistent with industry estimates**.

Many utilities filing Integrated Resource Plans ("IRP") with regulatory commissions throughout the country make reference to using price of electricity in their forecasting models. However, many either do not indicate the assumed or resultant price elasticities, or they protect the information under confidentiality arrangements. GDS identified three utilities that included elasticity information publicly in their IRP reports. Delmarva Power and Light reported a residential elasticity of -0.13 in its 2014 IRP. They assumed a price elasticity of demand of -0.04 for commercial and -0.14 for industrial. Ameren Missouri's 2014 IRP states that the residential price elasticity they use is -0.14. They also reference a study conducted a few years prior to the 2014 IRP in which they estimated a residential elasticity of -0.16. Big Rivers Electric Corporation[3] reported a price elasticity of -0.18 for all rural customers combined in their 2014 IRP. KU/LGE reports in its March 2014 IRP that they used elasticity estimates of -0.1 for residential and -0.05 for commercial. These estimates are all reasonably consistent with the results obtained for EKPC.

The National Renewal Energy Laboratory ("NREL") completed an analysis of price elasticity in February 2006.[4] They found national residential elasticity of -0.24 and an elasticity of -0.27 for the East South Central region (of which Kentucky is a part). The estimated nationwide commercial price elasticity was -0.21 and the East South Central estimate was -0.27. Although the commercial elasticity estimates for NREL are higher than the EKPC estimates, they are close enough for practical purposes[5]. NREL also conducted analysis at the state level and determined that the price elasticity coefficient for the Kentucky model was not significantly different than zero for both the residential and commercial classifications.

Finally, GDS examined an analysis conducted by the EIA[6]. The study examined, in part, the impacts on energy consumption of potential policies that would limit energy-related carbon dioxide emissions. More specifically, the impacts of a future fee on CO_2 emissions were analyzed for three carbon-fee cases, \$10, \$20, and \$30 per metric ton of CO_2 in 2020 and rising by 5 percent per year annually thereafter. The EIA study was conducted at the national level and for each Census region. EIA reports that the electricity sector alters investment and operating decisions to reduce CO_2 emissions in response to CO_2 fees, and customers react to resulting higher retail electricity prices by cutting demand. An analysis of the changes in electricity prices and energy consumption for the three carbon-fee cases relative to the EIA reference case was performed, and the elasticity of demand (energy consumption) with respect to price for the residential and commercial sectors combined was -0.21 for the East South Central region.

4.4 Conclusions

Based on the analysis conducted, various model specifications produce stable elasticity estimates for the residential and commercial customer classes. Results at the aggregate EKPC level produce reliable estimates of long-term price elasticity of demand for electricity consumption. The range of values estimated from models at the member cooperative level are somewhat volatile but within a reasonable range of the aggregate estimates. GDS recommends use of the aggregate model results for purposes of analyzing load response to price anywhere in the EKPC territory. Furthermore, the estimates derived in

[3] GDS prepared Big Rivers' 2014 IRP, including performing the price elasticity analysis. The elasticity assumption was reported in the public version of the IRP.

[4] Bernstein, M.A. and J. Griffin. "Regional Differences in the Price-Elasticity of Demand for Energy." NREL, Subcontractor Report NREL/SR-620-39512. February 2006.

[5] Although the elasticity estimate of -0.1 for EKPC is half as much as the elasticity estimate of -0.2 for NREL's regional model, the estimated load reduction per 1% increase in price is only 0.1% different between the two assumptions.

[6] Energy Information Administration, *Further Sensitivity Analysis of Hypothetical Policies to Limit Energy-Related Carbon Dioxide Emission*, Supplement to the Annual Energy Outlook 2013, July 2013. http://www.eia.gov/forecasts/aeo/supplement/co2/pdf/aeo2013_supplement.pdf

this analysis are consistent with the price elasticity assumptions used by the US Energy Information Administration for its Annual Energy Outlook forecasting, providing greater confidence in the results obtained herein.

- GDS recommends using a **RESIDENTIAL** price elasticity in the range of **-0.20 TO -0.30** as a reasonable assumption for load forecasting residential price sensitivities.
- GDS recommends using a **COMMERCIAL** price elasticity in the range of **-0.05 TO -0.15** as a reasonable assumption for load forecasting commercial price sensitivities.