MISO Energy and Peak Demand Forecasting for System Planning

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Executive Summary

This report provides the fifth load forecast the State Utility Forecasting Group (SUFG) has prepared for the Midcontinent Independent System Operator Inc. (MISO). These forecasts project annual MISO regional energy demand for the ten MISO local resource zones (LRZs), zonal summer and winter seasonal peak loads and MISO system-wide annual energy and peak demands. This forecast does not attempt to replicate the forecasts that are produced by MISO's load-serving entities (LSEs).

Econometric models were developed for each state to project annual retail sales of electricity. Forecasts of metered load at the LRZ level were developed by allocating the portion of each state's sales to the appropriate LRZ and adjusting for distribution system losses, weather and existing energy efficiency (EE) programs. LRZ seasonal peak demand projections were developed using peak conversion factors, which translated annual energy into peak demand based on historical observations assuming normal peak weather conditions. The LRZ peak demand forecasts are on a non-coincident basis.[1] MISO system level seasonal peak projections were developed from the LRZ forecasts using coincidence factors. EE adjustments were made at the LRZ level and the MISO system-wide level based on a study of performed by Applied Energy Group (AEG) for MISO. Results are provided without and with the EE adjustments.

The state econometric models were developed using publicly available economic data, namely annual electricity sales, prices for electricity and natural gas, personal income, population, employment, gross state product, and annual cooling and heating degree days. Economic and population projections acquired from IHS Markit (formerly IHS Global Insight) and price projections developed by SUFG were used to produce projections of future retail sales. Weather variables were held constant at their 30-year normal values. Table ES-1 provides the compound annual growth rates (CAGR) for the state energy forecasts.

LRZ level energy forecasts were developed by allocating the state energy forecasts to the individual LRZs on a proportional basis. Additionally, adjustments for distribution losses, normal weather and existing EE programs were made to produce a forecast at the metered load level. Table ES-2 provides the growth rates for the LRZ energy forecasts without and with the EE adjustments.

LRZ summer and winter non-coincident peak demand projections were developed using peak conversion factors that are determined from historical relationships between average hourly load for the year, summer and winter peak levels for the year, and weather conditions at the time of the peak demand. Since these conversion factors are held constant for the forecast period, the LRZ peak demand projections without the EE adjustments have the same growth rates as the energy projections in Table ES-2.[2] The compound annual growth rates of the LRZ non-coincident peak demand projections with the EE adjustments are shown in Table ES-3.

[1] Throughout this report, coincidence is stated in reference to the overall MISO system. Thus, the LRZ peak demand forecasts are for the highest level of demand for that particular LRZ, which would be coincident at the LRZ level but non-coincident at the MISO system level.

[2] It should be noted that if customer sectors grow at different rates, the assumption that energy and peak demand will grow at the same rate is unlikely to hold true. However, there has been very little long-term change in the relationship between energy and peak demand in the MISO region, with weather variations having a much larger impact.

Table ES-1 State Retail Sales (without EE Adjustments) Compound Annual Growth Rates (2019-2038)

State	CAGR
Arkansas	1.10
Illinois	0.48
Indiana	1.15
Iowa	1.41
Kentucky	0.90
Louisiana	0.41
Michigan	0.57
Minnesota	0.71
Mississippi	1.37
Missouri	0.89
Montana	1.17
North Dakota	1.47
South Dakota	1.60
Texas	1.72
Wisconsin	1.10

Table ES-2 LRZ Metered Load Annual Growth Rates (2019-2038)

LRZ	CAGR (without EE Adjustments)	CAGR (with EE Adjustments)
1	0.88	0.76
2	1.06	0.84
3	1.37	0.94
4	0.48	0.20
5	0.28	0.07
6	1.05	1.00
7	0.57	0.42
8	1.10	0.77
9	0.72	0.69
10	1.37	1.37

Table ES-3 LRZ Non-Coincident Summer and Winter Peak Demand (with EE Adjustments) Compound Annual Growth Rates (2019-2038)

LRZ	CAGR (with EE Adjustments on Non-Coincident Peak)	
	Summer	Winter
1	0.73	0.70
2	0.78	0.70
3	0.84	0.69
4	0.13	0.04
5	0.01	-0.05
6	0.98	0.97
7	0.39	0.31
8	0.75	0.67
9	0.68	0.68
10	1.37	1.37

MISO system-wide energy and peak demand projections were developed from the LRZ-level projections. Since each LRZ does not experience its peak demand at the same time as the others (or as the entire MISO system), the MISO coincident peak demand is less than the arithmetic sum of the individual LRZ non-coincident peak demands. The MISO system coincident peak demand is determined by applying coincidence factors to the individual LRZ non-coincident peak demands and summing. These coincidence factors represent the ratio of the LRZ's load at the time of the overall MISO system peak to the LRZ's non-coincident peak. Coincidence factors were developed for the summer and winter peaks. Since coincidence is not an issue for annual energy, the MISO energy projections are found from the simple sum of the individual LRZs' energy projections. Table ES-4 provides the compound annual growth rates for the MISO energy and peak demand forecasts on a gross and net basis.

Table ES-4. MISO Energy and Seasonal Peak Demand Growth Rates (2019-2038)

MISO-System	Gross CAGR (without EE Adjustments)	Net CAGR (with EE Adjustments)
Energy	0.86	0.70
Summer Peak Demand	0.85	0.66
Winter Peak Demand	0.86	0.62

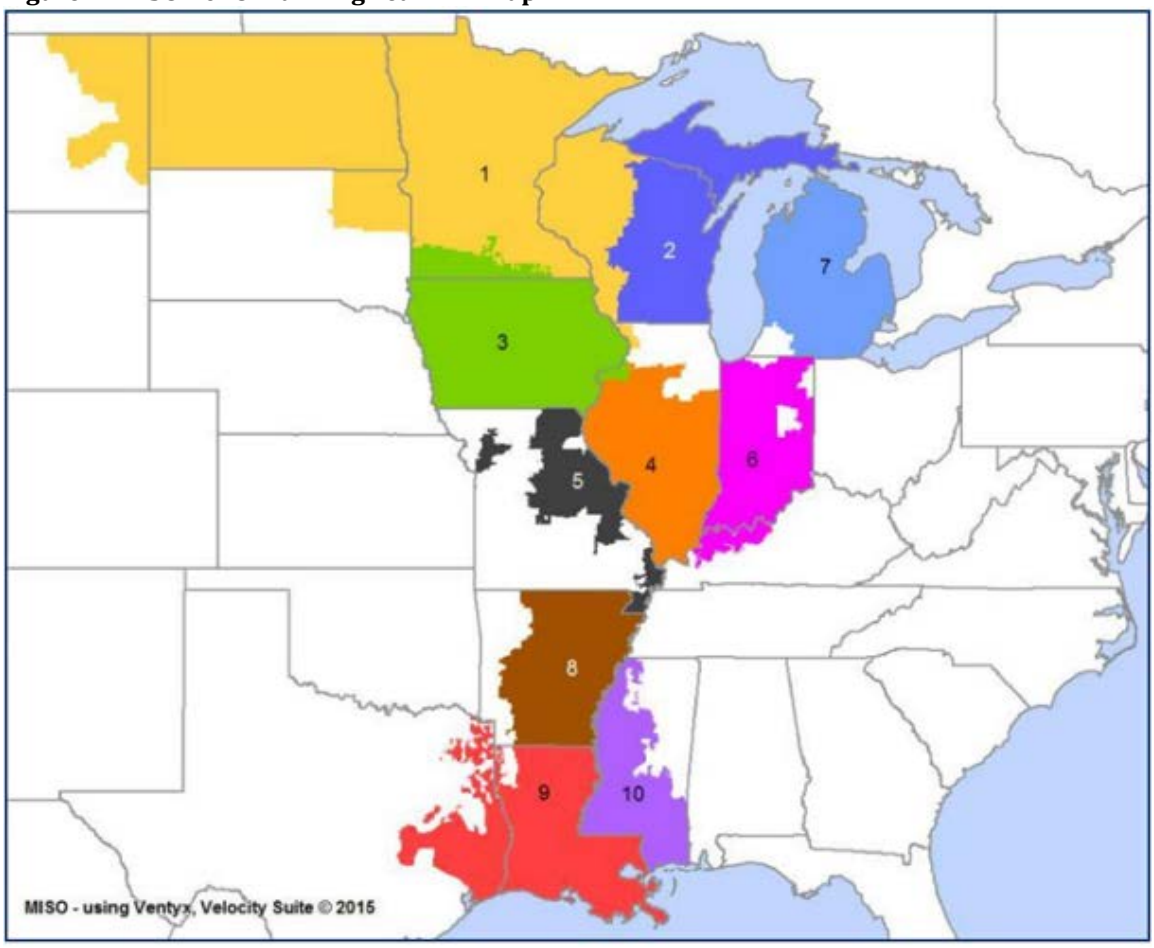
1 Introduction

This report represents the fifth load forecast the State Utility Forecasting Group (SUFG) has prepared for the Midcontinent Independent System Operator Inc. (MISO). These forecasts project annual MISO regional energy demand for the ten MISO local resource zones (LRZs), regional winter and summer seasonal peak loads and MISO system-wide annual energy and peak demands. This forecast does not attempt to replicate the forecasts that are produced by MISO's load-serving entities (LSEs).

1.1 OVERVIEW

The MISO market footprint consists of a number of individual Local Balancing Authorities (LBAs). It covers all or parts of 15 states and is divided into 10 LRZs[3]. Figure 1 displays the MISO market footprint at the LRZ level.

Figure 1: MISO 2018 Planning Year LRZ Map



Source: MISO, 2018

[3] A very small amount of load in Oklahoma and Tennessee is served by MISO LBAs in LRZ 8. Rather than developing individual state econometric models for those states, it is assumed that these loads grow at the rate of the rest of LRZ 8.

Econometric models were developed for each state to project annual retail sales of electricity. Forecasts of metered load at the LRZ level were developed by allocating the portion of each state's sales to the appropriate LRZ and adjusting for distribution system losses, weather, existing energy efficiency (EE) programs based on the difference between the estimate of LRZ retail sales from state sales forecast for the year 2017 and the weather-normalized LRZ metered load for the year 2017. LRZ seasonal peak demand projections were developed using peak load conversion factors, which translated annual energy into peak demand based on historical observations assuming normal peak weather conditions. The LRZ peak demand forecasts are on a non-coincident basis[4], which means each zone may reach its annual zonal peak at a different time. MISO system level projections were developed from the LRZ forecasts. For the seasonal MISO-wide peak demands, coincidence factors were used. EE adjustments were made at the LRZ level based on a study performed by Applied Energy Group (AEG) for MISO. Zonal energy and peak forecast results are provided without and with the EE adjustments for the period of 2019 to 2038.

1.2 REPORT STRUCTURE

In this report, Chapter 2 explains the forecasting methodology and provides the data sources. Chapter 3 summarizes state energy projection profiles including descriptions of the state econometric models and the resulting energy forecasts. Chapter 4 covers forecast results by LRZ both without and with the EE adjustments. Chapter 5 provides MISO system level results. The report contains five appendices. Appendix A provides details of the state energy forecasting models and methodology. Appendix B explains the calculation of allocation factors and the process for allocating the state energy forecasts to LRZ-level forecasts. Appendix C provides the methodology for determining the peak demand forecasts. Appendix D briefly describes the weather normalization methodology and appendix E lists high and low forecasts of energy and peak demand at state and LRZ levels.

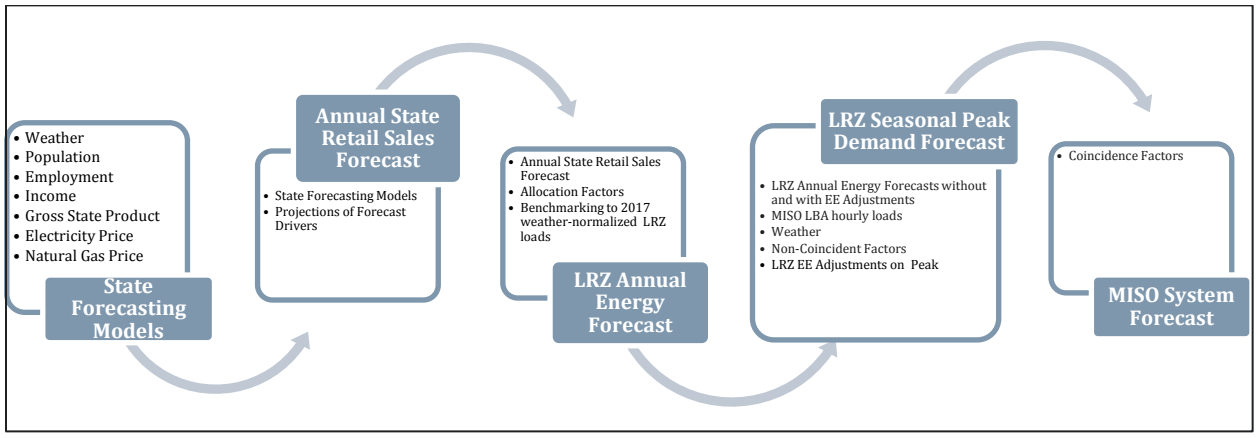
[4] Throughout this report, coincidence is stated in reference to the overall MISO system. Thus, the LRZ peak demand forecasts are for the highest level of demand for that particular LRZ, which would be coincident at the LRZ level but non-coincident at the MISO system level.

2 Forecasting Methodology

2.1 OVERVIEW

This study employed a multi-step approach to forecast annual energy and seasonal peak demand at the MISO LRZ and system-wide levels. Econometric models were built for each state to forecast retail sales for a 20-year period, namely 2019 to 2038. The statewide energy forecasts were then used to construct annual energy forecasts at the LRZ level based on the allocation factors aggregating state-level MISO sales to zonal energy projection. The LRZ annual energy forecasts were used, in turn, to develop seasonal non-coincident peak demand projections for each LRZ. The LRZ coincident peak projections are estimated from non-coincident peak demand projections based on zonal coincident factors. The overall process flow chart is illustrated in Figure 2 below. It shows the five major steps in the process and the key inputs at each step.

Figure 2: Process Flow Chart



2.2 STATEWIDE ANNUAL ELECTRIC ENERGY FORECASTS

Econometric models of retail electricity sales were developed for each state using statewide historical data to determine the appropriate drivers of electricity consumption and the statistical relationship between those drivers and energy consumption. SUFG developed numerous possible model specifications for each state and selected models that had a good fit (significant t-statistics, high R-squared, and a significant F-statistic), that passed the statistical tests (heteroskedasticity and serial correlation), and had a set of drivers that included at least one driver that was tied to the overall growth in the state (such as employment, population and GSP). The model formulations by state are provided in Appendix A.

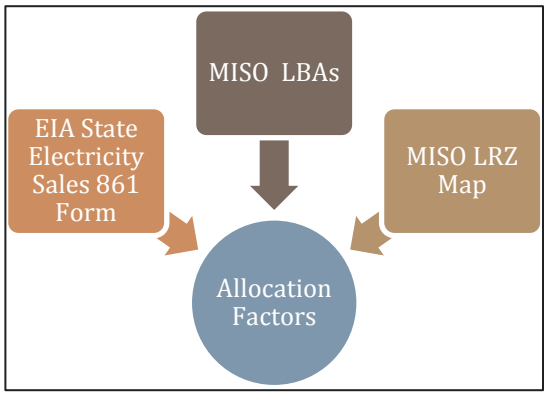
2.3 CONVERSION OF RETAIL SALES TO METERED LOAD AND BENCHMARKING TO 2017 LEVELS

The state-level forecasts represent annual (calendar year) retail sales (electricity usage at the customer locations). This is driven by data availability, since statewide historical sales are available from the U.S. Department of Energy's Energy Information Administration (EIA). Since 2017 state electricity sales data was not available at the time this report was prepared, the state sales numbers for that year represent a forecast value that is not adjusted for energy efficiency programs. The LRZ-level forecasts are at the metered level (in essence, loads at the substations where the transmission network operated by MISO connects to the distribution systems). The difference between the two is caused by losses between the substations and

customers.[5] Since the historical metered loads at the LRZ-level are known for 2017 (they are provided by MISO), SUFG benchmarked the LRZ-level forecasts to the weather-normalized metered load levels for that year. This benchmarking accomplishes two objectives: it converts the forecast from the retail sales level to the metered load level and it captures the energy efficiency program savings for 2017.

2.4 LRZ ENERGY FORECASTS

Figure 3: Structure and Logic Diagram for Allocation Factors

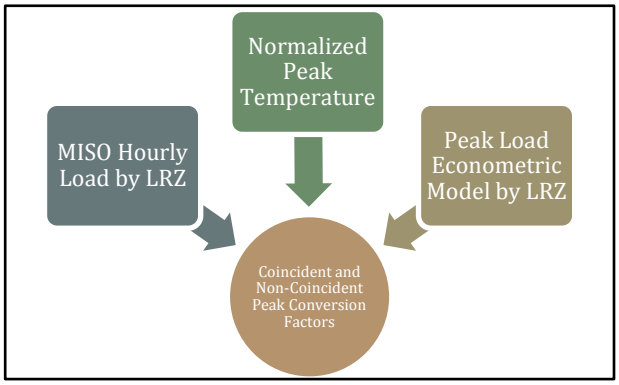


The LRZ annual energy forecasts were produced after the individual state annual forecasts were developed. This was done by allocating the fraction of each state's load to the appropriate LBA within that state (herein referred to as the load fraction) and summing across the various LBAs within each LRZ (Figure 3). Since not all regions within a state experience load growth at the same rate, the load fraction of each state may change over time. The historical load fractions of each state were calculated and used to estimate the future allocation factors. Additional adjustments also have been made to account for LBAs that operate in more than one state. In these cases, the market share of the LBA's load in each state within its service territory has been calculated in order to determine its load fraction for that state. In addition, the distribution losses of each LRZ were incorporated (refer to section 2.3). The MISO system-wide energy forecast was obtained by summing the LRZ annual energy forecasts. See Appendix B for additional details on the allocation process.

In addition, the EE adjustments to the LRZ energy forecasts were made based on a study of those factors performed by AEG for MISO. Both non-adjusted and adjusted projections are provided at the LRZ level.

2.5 LRZ NON-COINCIDENT PEAK DEMAND FORECASTS

Figure 4: Structure and Logic Diagram for Peak Conversion Factors



The non-coincident peak demand forecasts were estimated based on load factors calculated using historical hourly load data of each LRZ provided by MISO. The structure and logic diagram in Figure 4 illustrates the resources employed in estimating the peak conversion factors. Peak load conversion factors were used to translate annual electricity sales forecasts at the LRZ level to summer and winter non-coincident peak demands. These conversion factors were determined from historical relationships between average hourly load for the year, summer/winter peak levels for the year, and weather conditions at the time of the peak demand. See Appendix C for additional information on the peak demand methodology.

[5] These losses occur mainly in the distribution system of the load serving entities and may include some low voltage transmission lines that are not under MISO operation.

2.6 MISO-LEVEL FORECASTS

The non-coincident LRZ peak demand projections were converted to MISO-level coincident peak demands using historical average coincidence factors. The coincidence factor for each LRZ is determined at the time of the MISO system-wide peak demand using the ratio of the LRZ's demand at the time of the MISO-wide (coincident) peak demand divided by the LRZ's demand at the time of the LRZ's individual (non-coincident) peak demand. The MISO system-wide peak demand forecast was obtained by summing the coincident LRZ peak demands. Since coincidence is not an issue with annual energy, the MISO system-wide annual energy forecast is the arithmetic sum of the LRZ annual energy forecasts.

2.7 DATA SOURCES

Historical annual energy sales data and electricity and natural gas prices by state were obtained from EIA. Historical population data by state were obtained from the Census Bureau. Historical macroeconomic data, such as personal income, were obtained from the Bureau of Economic Analysis (BEA); gross state product data were obtained from IHS Markit (formerly IHS Global Insight) to avoid inconsistency in BEA data due to a change in industry classification systems; and employment data were obtained from the Bureau of Labor Statistics (BLS). Projections of macroeconomic data and population were provided by IHS Markit. Electricity and natural gas price projections were developed by SUFG. Actual monthly heating and cooling degree days on a 65 degree Fahrenheit basis for all 15 states were obtained from the National Oceanic and Atmospheric Administration (NOAA), and were aggregated to annual data by state. Normal weather by state used in projections were obtained from NOAA. Zonal hourly temperature records were acquired from Midwest Regional Climate Center (MRCC). Table 1 summarizes the sources of data used in this study.

Table 1: Data Sources

Data	Content	Historical Data Source	Data Used in Projection
Electricity sales	GWhs, annual retail electricity sales by state, 1990-2016	EIA	N/A
Electricity prices	Cents/KWh, 2009$, 1990-2016	EIA*	SUFG projection based on EIA data
Natural gas prices	$/Mcf (thousand cubic feet), 2009$, 1990-2016	EIA*	SUFG projection based on EIA data
Real personal income	Thousands, 2009$, 1990-2016	BEA*	IHS Markit
Population	Number of people, population by state, 1990-2016	Census Bureau	IHS Markit
Manufacturing & non-manufacturing employment	Number of jobs, 1990-2016	BLS	IHS Markit
Non-farm employment	Number of jobs, 1990-2016	BLS	IHS Markit
Gross state product	Millions, 2009$, 1990-2016	IHS Markit	IHS Markit
Cooling degree days (CDD)	Summations of monthly cooling degree days, base 65°F, 1970-2017	NOAA	NOAA 30-year normal
Heating degree days (HDD)	Summations of monthly heating degree days, base 65°F, 1970-2017	NOAA	NOAA 30-year normal
Hourly Temperature	Historical hourly temperature of selected weather stations, 1997-2017	MRCC	Normal peak temperatures

** Original data was in nominal dollars. SUFG converted it to real 2009 dollars using CPI data obtained from BLS.*

2.8 Modeling Enhancements

The overall modeling methodology is similar to the one employed in 2017. Two adjustments were incorporated to enhance and refine model outputs: 1) the LRZ-level energy forecasts are benchmarked to the most recent historical year; 2) seasonal peak load factor modeling has been refined. In previous forecasts, an adjustment factor was used to convert retail sales to metered load. This adjustment was based on the average of historical distribution losses calculated by comparing LRZ retail sales aggregated from EIA data and the corresponding LRZ metered load provided by MISO. Due to delays in data availability at the state level, this model did not adequately capture utility-sponsored energy efficiency programs in the most recent historical year. For this year's forecast, the adjustment is determined by comparing the estimate of LRZ retail sales from state sales forecasts for the year 2017 and the weather-normalized LRZ metered load for the year 2017, which factors in weather adjustments and existing EE program adjustments in addition to distribution losses according to the most recent record (2017 hourly zonal data) available. The seasonal peak modeling employed stepwise model selection with an expanded potential variable pool. Please refer to Appendix C for peak demand methodology.

In addition to those model revisions, a number of models were updated to reflect additional historical data. These include the state econometric models (previously estimated in 2016), the state to LRZ allocation factors, LRZ coincidence factors, and the models used to develop the drivers for the alternate low and high forecasts.

3 State-by-State Results

3.1 ARKANSAS

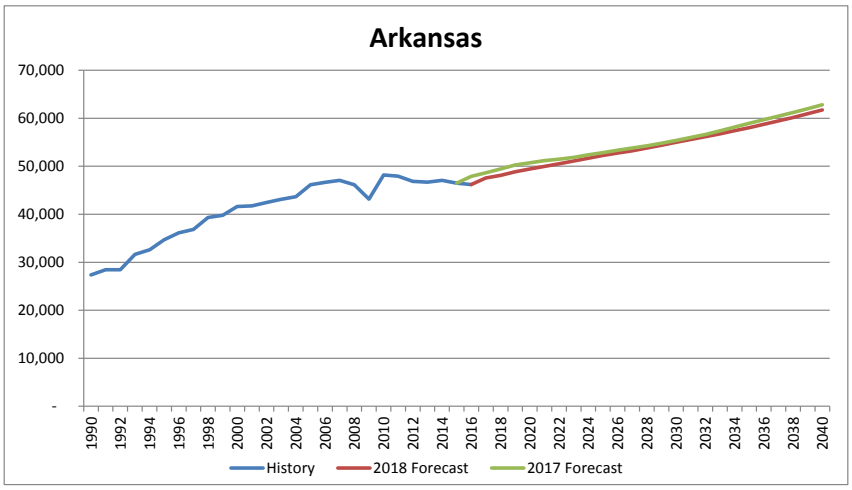
The Arkansas state econometric model uses real gross state product, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 2.

Table 2: Arkansas Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real GSP
0.39	0.87	1.65

Gross electricity sales are projected to grow at 1.10% in this forecast, which is very close to the 1.06% growth projected in 2017. Figure 5 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 5: Arkansas Gross Energy Forecasts (Annual Retail Sales in GWh)



Most of Arkansas's loads are in LRZ 8. The Arkansas gross forecast is allocated to that LRZ based on the historical average of the load fractions, as shown in Table 3. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 3: Arkansas Allocation Factors (%)

LRZ 8	Non-MISO
71.1%	28.9%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Arkansas's LRZ are shown in Table 4. Section 3 contains more information on the LRZ forecasts.

Table 4: Arkansas LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ8	1.10	0.77	1.10	0.75	1.10	0.67

3.2 ILLINOIS

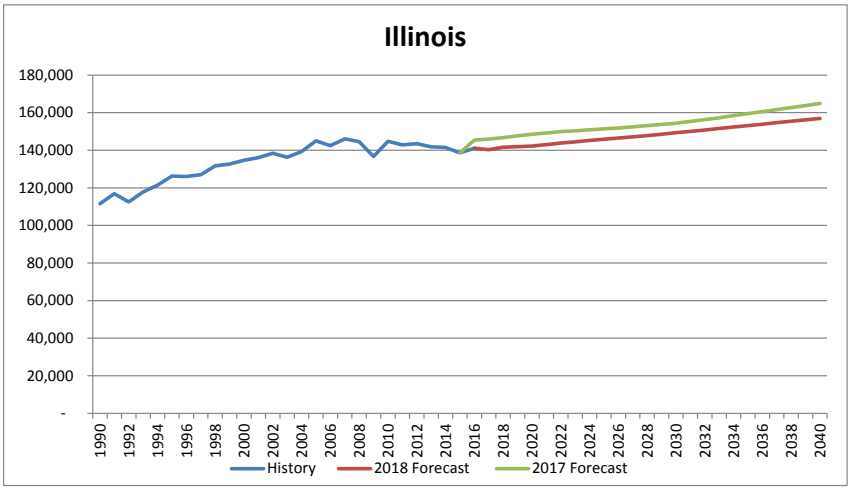
The Illinois state econometric model uses real personal income, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 5.

Table 5: Illinois Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real Income
0.10	0.91	1.44

Gross electricity sales are projected to grow at 0.48% in this forecast, which is slightly lower than the 0.51% growth projected in 2017. Figure 6 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 6: Illinois Gross Energy Forecasts (Annual Retail Sales in GWh)



Illinois has loads in three LRZs (1, 3, and 4), with roughly 2/3 of the state's loads located outside MISO. The Illinois gross forecast is allocated to those LRZs based on the historical average of load fractions, as show in Table 6. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 6: Illinois Allocation Factors (%)

LRZ 1	LRZ 3	LRZ 4	Non-MISO
0.0002%	1.4%	33.1%	65.5%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Illinois's LRZs are shown in Table 7. Section 3 contains more information on the LRZ forecasts.

Table 7: Illinois LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70
LRZ3	1.37	0.94	1.37	0.84	1.37	0.69
LRZ4	0.48	0.20	0.48	0.13	0.48	0.04

3.3 INDIANA

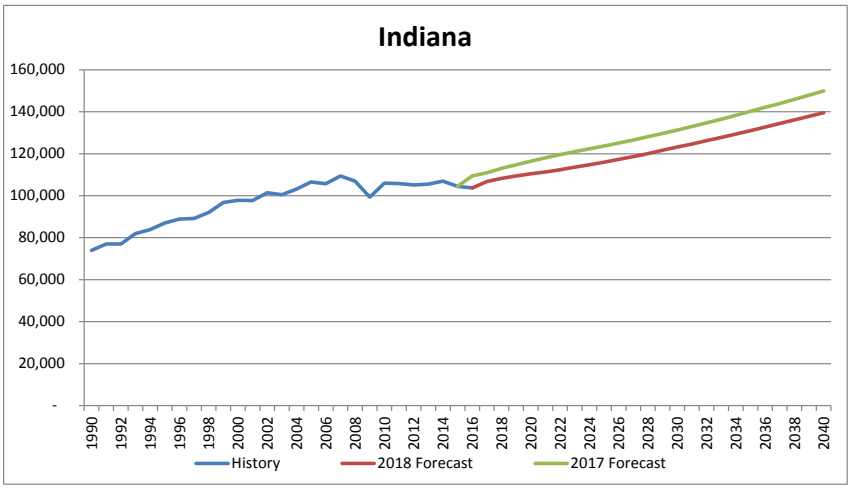
The Indiana state econometric model uses real gross state product, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 8.

Table 8: Indiana Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real GSP
0.09	0.88	1.65

Gross electricity sales are projected to grow at 1.15% in this forecast, which is lower than the 1.28% growth projected in 2017. Figure 7 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 7: Indiana Gross Energy Forecasts (Annual Retail Sales in GWh)



Most of Indiana's loads are in LRZ 6. Per the request of MISO staff and due to concerns over providing utility-specific information in states that only have a single MISO utility, the load fraction of Indiana and Kentucky are combined (IN+KY). The IN+KY gross forecasts are allocated to those LRZs based on the historical average of the load fractions, as shown in Table 9. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

The shutdown of the Paducah Gaseous Diffusion Plant in Kentucky in 2013 caused a significant shift in the historical MISO share in IN+KY. Because the 2014, 2015 and 2016 values reflect the MISO shares in LRZ 6 after the complete shutdown of the plant, the future allocation factor is held constant at those values.

Table 9: Indiana and Kentucky Allocation Factors (%)

LRZ 6	Non-MISO
51.6%	48.4%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates of LRZ 6 are shown in Table 10. Section 3 contains more information on the LRZ forecasts.

Table 10: Indiana and Kentucky LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ6	1.05	1.00	1.05	0.98	1.05	0.97

3.4 IOWA

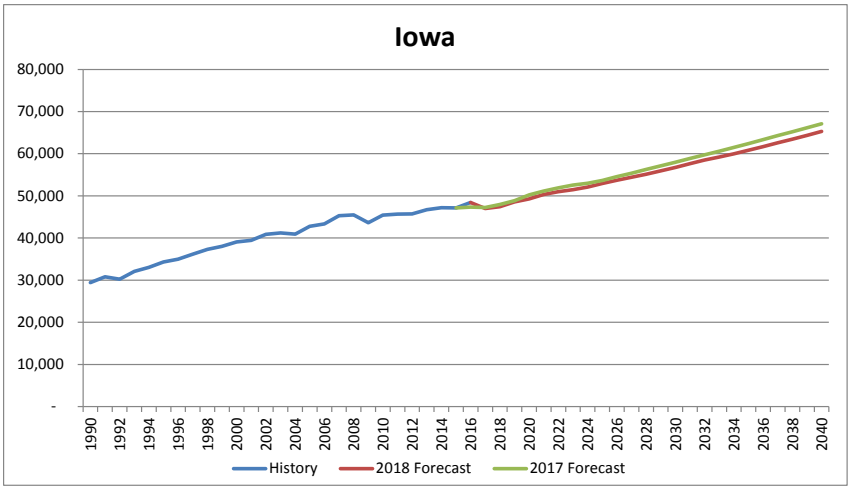
The Iowa state econometric model uses real personal income, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 11.

Table 11: Iowa Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real Income
0.07	0.84	1.80

Gross electricity sales are projected to grow at 1.41% in this forecast, which is somewhat lower than the 1.55% growth projected in 2017. Figure 8 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 8: Iowa Gross Energy Forecasts (Annual Retail Sales in GWh)



Iowa has loads in two LRZs (1 and 3). The Iowa gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 12. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 12: Iowa Allocation Factors (%)

LRZ 1	LRZ 3	Non-MISO
1.79	91.08	7.13

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Iowa's LRZs are shown in Table 13. Section 3 contains more information on the LRZ forecasts.

Table 13: Iowa LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
1	0.88	0.76	0.88	0.73	0.88	0.70
3	1.37	0.94	1.37	0.84	1.37	0.69

3.5 KENTUCKY

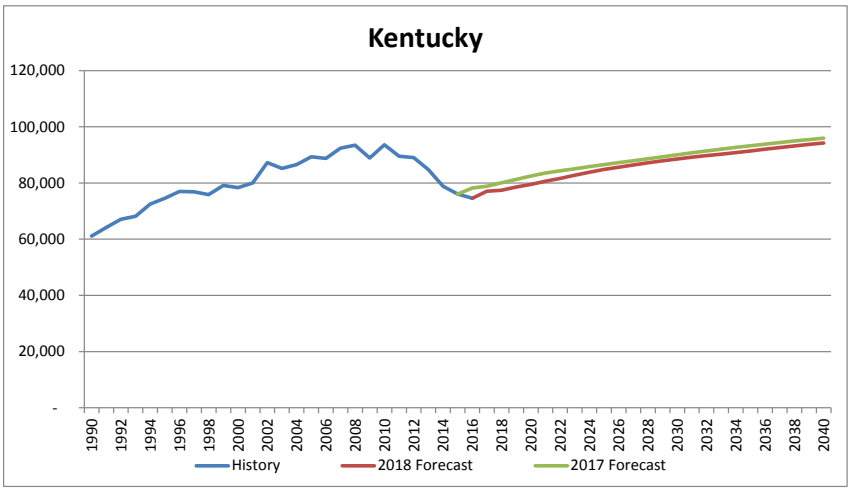
The Kentucky state econometric model uses population, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 14.

Table 14: Kentucky Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Population
-0.15	0.8	0.38

For the state of Kentucky, SUFG observed a dramatic drop in electricity sales occurred starting in 2013. This was caused by the closure of the Paducah Gaseous Diffusion Plant (PGDP) in mid-2013, which represented a 3 GW load on the Tennessee Valley Authority (TVA) system and accounted for more than 10% of the state's retail sales. With this large drop in load, SUFG could not fit an econometric model for the state. Therefore, the 2013 and subsequent years historical load were adjusted up to what it would have been with the PGDP operated at its full capacity. SUFG then developed the econometric model with the adjusted electricity load and used the model to produce a load forecast for the state of Kentucky. The PGDP load was then subtracted from the forecast load derived from the econometric model to serve as the final state load forecast for Kentucky. Gross electricity sales are projected to grow at 0.90% in this forecast, which is slightly higher than the 0.87% growth projected in 2017. However, since the 2018 forecast starts lower than the 2017 forecast, the trajectory for the current forecast is slightly lower. Figure 9 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 9: Kentucky Gross Energy Forecasts (Annual Retail Sales in GWh)



Only a small part of Kentucky's loads are in LRZ 6, with most of the load occurring outside of MISO. Per the request of MISO staff and due to concerns over providing utility-specific information in states that only have a single MISO utility, the load fraction of Indiana and Kentucky are combined (IN+KY). The IN+KY gross forecasts are allocated to those LRZs based on the historical average of the load fractions, as shown in Table 15. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

The shutdown of the PGDP facility in 2013 caused a significant shift in the historical MISO share in IN+KY. Because the 2014, 2015 and 2016 values reflect the MISO shares in LRZ 6 after the complete shutdown of the plant, the future allocation factor is held constant at those values.

Table 15: Indiana and Kentucky Allocation Factors (%)

LRZ 6	Non-MISO
51.6%	48.4%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Indiana and Kentucky's LRZ are shown in Table 16. Section 3 contains more information on the LRZ forecasts.

Table 16: Indiana and Kentucky LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ6	1.05	1.00	1.05	0.98	1.05	0.97

3.6 LOUISIANA

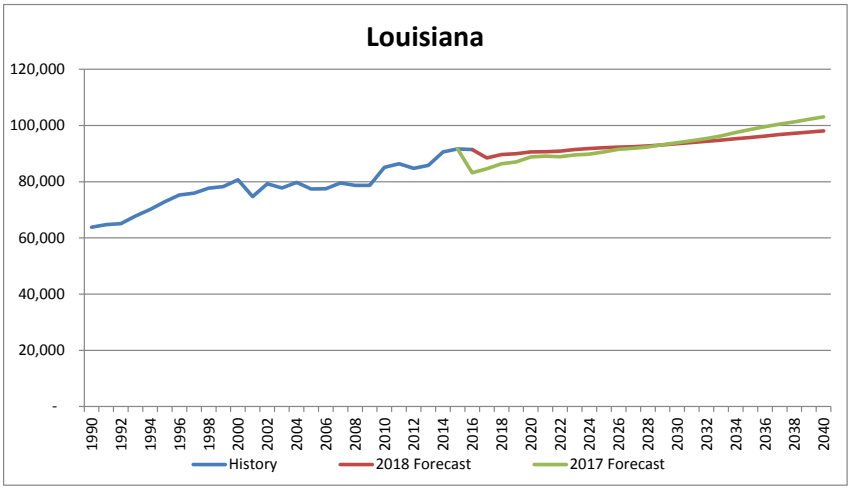
The Louisiana state econometric model uses real personal income, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 17.

Table 17: Louisiana Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real Income
0.39	1.19	1.38

Gross electricity sales are projected to grow at 0.41% in this forecast, which is lower than the 0.80% growth projected in 2017. Figure 10 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 10: Louisiana Gross Energy Forecasts (Annual Retail Sales in GWh)



Most of Louisiana's loads are in LRZ 9. The Louisiana gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 18. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 18: Louisiana Allocation Factors (%)

LRZ 9	Non-MISO
92.2%	7.8%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Louisiana's LRZ are shown in Table 19. Section 3 contains more information on the LRZ forecasts.

Table 19: Louisiana LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ9	0.72	0.69	0.72	0.68	0.72	0.68

3.7 MICHIGAN

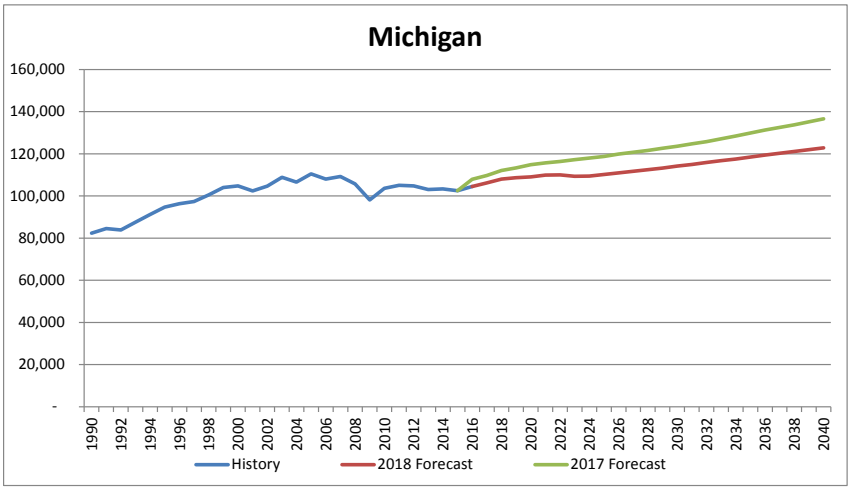
The Michigan state econometric model uses real personal income, real electricity prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 20.

Table 20: Michigan Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Income
0.1	1.27

Gross electricity sales are projected to grow at 0.57% in this forecast, which is lower than the 0.88% growth projected in 2017. Figure 11 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 11: Michigan Gross Energy Forecasts (Annual Retail Sales in GWh)



Michigan has loads in three LRZs (1, 2 and 7). The Michigan gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 21. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 21: Michigan Allocation Factors (%)

LRZ 1	LRZ 2	LRZ 7	Non-MISO
0.1%	4.9%	91.0%	4.0%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Michigan's LRZs are shown in Table 22. Section 3 contains more information on the LRZ forecasts.

Table 22: Michigan LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70
LRZ2	1.06	0.84	1.06	0.78	1.06	0.70
LRZ7	0.57	0.42	0.57	0.39	0.57	0.31

3.8 MINNESOTA

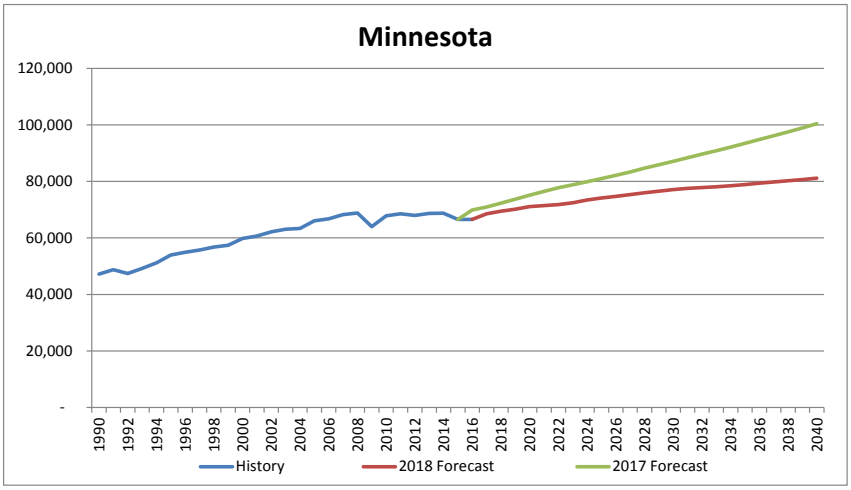
The Minnesota state econometric model uses real personal income, real electricity prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 23.

Table 23: Minnesota Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Population
0.05	0.46

Gross electricity sales are projected to grow at 0.71% in this forecast, which is lower than the 1.52% growth projected in 2017. Figure 12 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 12: Minnesota Gross Energy Forecasts (Annual Retail Sales in GWh)



Minnesota has loads in two LRZs (1 and 3). The Minnesota gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 24. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 24: Minnesota Allocation Factors (%)

LRZ 1	LRZ 3	Non-MISO
97.0%	0.9%	2.1%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Minnesota's LRZs are shown in Table 25. Section 3 contains more information on the LRZ forecasts.

Table 25: Minnesota LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70
LRZ3	1.37	0.94	1.37	0.84	1.37	0.69

3.9 MISSISSIPPI

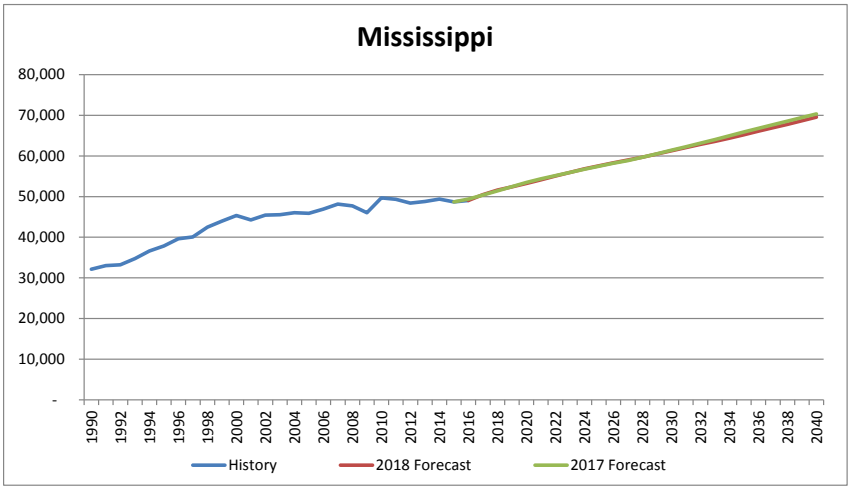
The Mississippi state econometric model uses real personal income, real electricity prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 26.

Table 26: Mississippi Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Income	Real GSP
-0.15	1.63	1.57

Gross electricity sales are projected to grow at 1.37% in this forecast, which is somewhat lower than the 1.46% growth projected in 2017. Figure 13 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 13: Mississippi Gross Energy Forecasts (Annual Retail Sales in GWh)



About half of Mississippi's load is in LRZ 10. The Mississippi gross forecast is allocated to this LRZ based on the historical average of the load fractions, as shown in Table 27. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 27: Mississippi Allocation Factors (%)

LRZ 10	Non-MISO
45.1%	54.9%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Mississippi's LRZ are shown in Table 28. Section 3 contains more information on the LRZ forecasts.

Table 28: Mississippi LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ10	1.37	1.37	1.37	1.37	1.37	1.37

3.10 MISSOURI

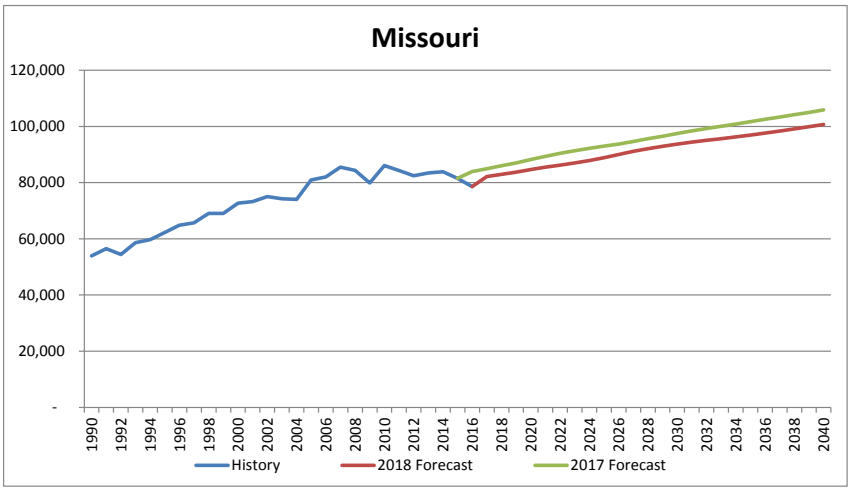
The Missouri state econometric model uses population, manufacturing employment, real electricity prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 29.

Table 29: Missouri Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Population	Manufacturing Employment
0.06	0.4	-0.14

Gross electricity sales are projected to grow at 0.89% in this forecast, which is somewhat lower than the 0.97% growth projected in 2017. Figure 14 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 14: Missouri Gross Energy Forecasts (Annual Retail Sales in GWh)



Missouri has loads in two LRZs (5 and 8). The Missouri gross forecast is allocated to those LRZs based on the trend of historical load fractions, as shown in Table 30. Based on the projections of the values from the model drivers for the state of Missouri and for the St. Louis metropolitan statistical area from IHS Markit, the non-MISO region is projected to grow faster than the MISO region. Therefore, the allocation factor for LRZ5 is reduced from 48.46% in 2017 to 42.53% in 2038. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 30: Missouri Allocation Factors (%)

LRZ 5	LRZ 8	Non-MISO
Reduced from 48.46% in 2017 to 42.53% in 2038	0.02%	Change accordingly

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Missouri's LRZs are shown in Table 31. Section 3 contains more information on the LRZ forecasts.

Table 31: LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ5	0.28	0.07	0.28	0.01	0.28	-0.05
LRZ8	1.10	0.77	1.10	0.75	1.10	0.67

3.11 MONTANA

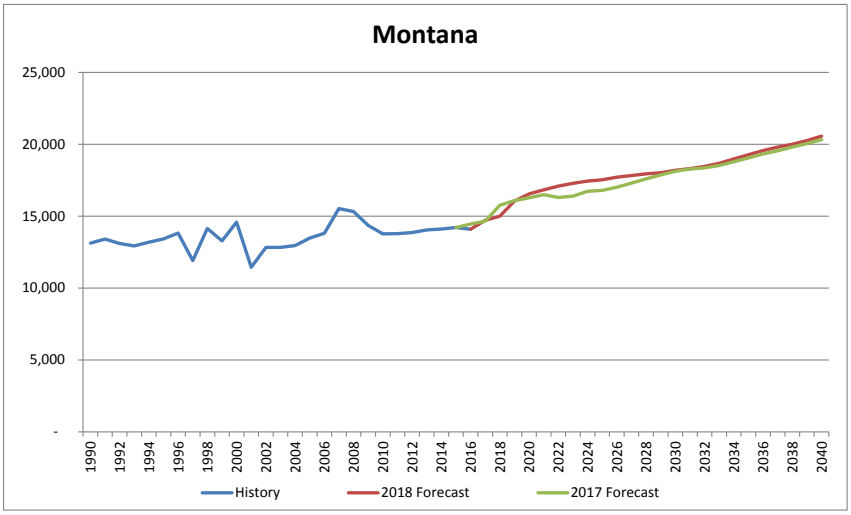
The Montana state econometric model uses real personal income per capita, manufacturing employment, real electricity price and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 32.

Table 32: Montana Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real Income/Population	Manufacturing Employment
0.43	0.96	1.28	-0.04

Gross electricity sales are projected to grow at 1.17% in this forecast, which is similar to the 1.14% growth projected in 2017. Figure 15 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 15: Montana Gross Energy Forecasts (Annual Retail Sales in GWh)



A small portion of Montana's loads is located in LRZ 1, with the remainder outside MISO. Per the request of MISO staff and due to concerns over providing utility-specific information in states that only have a single MISO utility, the load fraction of Montana and North Dakota are combined (MT+ND). The MT+ND gross forecasts are allocated to those LRZs based on the historical average of the load fractions, as shown in Table 33. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 33: Montana and North Dakota Allocation Factors (%)

LRZ 1	Non-MISO
36.4%	63.6%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Montana's LRZ are shown in Table 34. Section 3 contains more information on the LRZ forecasts.

Table 34: Montana and North Dakota LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70

3.12 NORTH DAKOTA

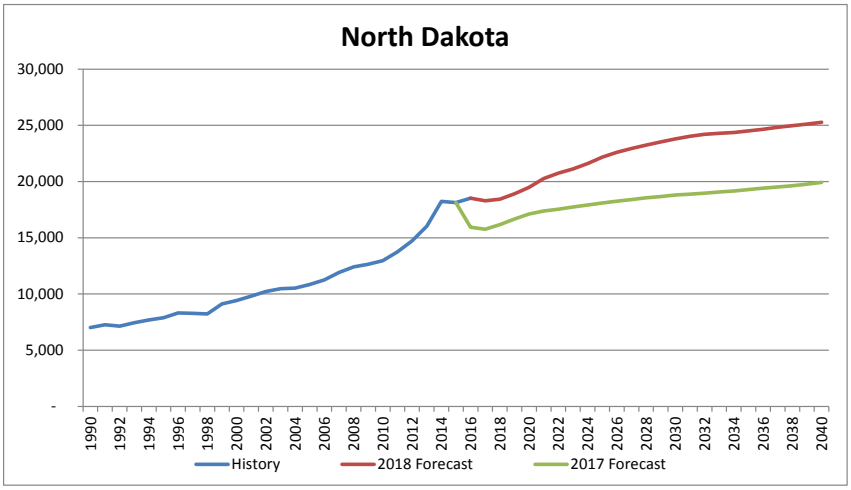
The North Dakota state econometric model uses population, real electricity prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 35.

Table 35: North Dakota Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Population
0.05	0.48

Gross electricity sales are projected to grow at 1.47% in this forecast, which is much higher than the 0.99% growth projected in 2017. Figure 16 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 16: North Dakota Gross Energy Forecasts (Annual Retail Sales in GWh)



North Dakota has loads located in LRZ 1. Per the request of MISO staff and due to concerns over providing utility-specific information in states that only have a single MISO utility, the load fraction of Montana and North Dakota are combined (MT+ND). The MT+ND gross forecasts are allocated to those LRZs based on the historical average of the load fractions, as shown in Table 36. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 36: Montana and North Dakota Allocation Factors (%)

LRZ 1	Non-MISO
36.4%	63.6%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for North Dakota's LRZ are shown in Table 37. Section 3 contains more information on the LRZ forecasts.

Table 37: Montana and North Dakota LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70

3.13 SOUTH DAKOTA

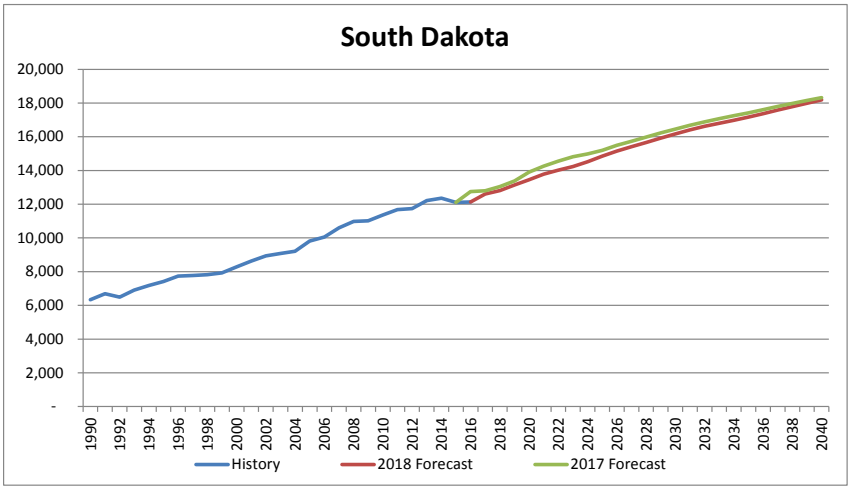
The South Dakota state econometric model uses population, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 38.

Table 38: South Dakota Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Population
0.05	0.86	0.69

Gross electricity sales are projected to grow at 1.60% in this forecast, which is similar to the 1.65% growth projected in 2017. Figure 17 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 17: South Dakota Gross Energy Forecasts (Annual Retail Sales in GWh)



South Dakota has loads in two LRZs (1 and 3). The South Dakota gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 39. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 39: South Dakota Allocation Factors (%)

LRZ 1	LRZ 3	Non-MISO
24.1%	1.8%	74.1%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for South Dakota's LRZs are shown in Table 40. Section 3 contains more information on the LRZ forecasts.

Table 40: South Dakota LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ1	0.88	0.76	0.88	0.73	0.88	0.70
LRZ3	1.37	0.94	1.37	0.84	1.37	0.69

3.14 TEXAS

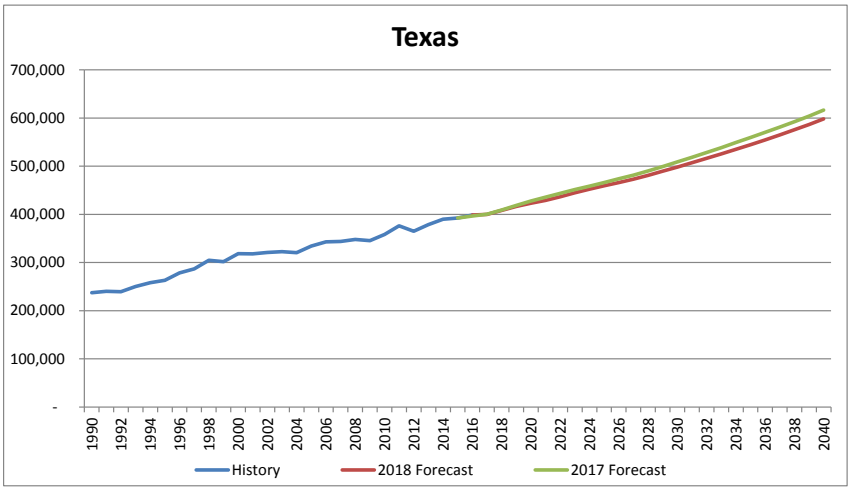
The Texas state econometric model uses real gross state product, real electricity prices and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 41.

Table 41: Texas Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real GSP
0.38	1.04	2.7

Gross electricity sales are projected to grow at 1.72% in this forecast, which is slightly lower than the 1.86% growth projected in 2017. **Figure** 19 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 18: Texas Gross Energy Forecasts (Annual Retail Sales in GWh)



Texas has loads in two LRZs (8 and 9). The Texas gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in Table 42. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 42: Texas Allocation Factors (%)

LRZ 8	LRZ 9	Non-MISO
0.01%	5.6%	94.4%

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Texas's LRZs are shown in Table 43. Section 3 contains more information on the LRZ forecasts.

Table 43: Texas LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
LRZ8	1.10	0.77	1.10	0.75	1.10	0.67
LRZ9	0.72	0.69	0.72	0.68	0.72	0.68

3.15 WISCONSIN

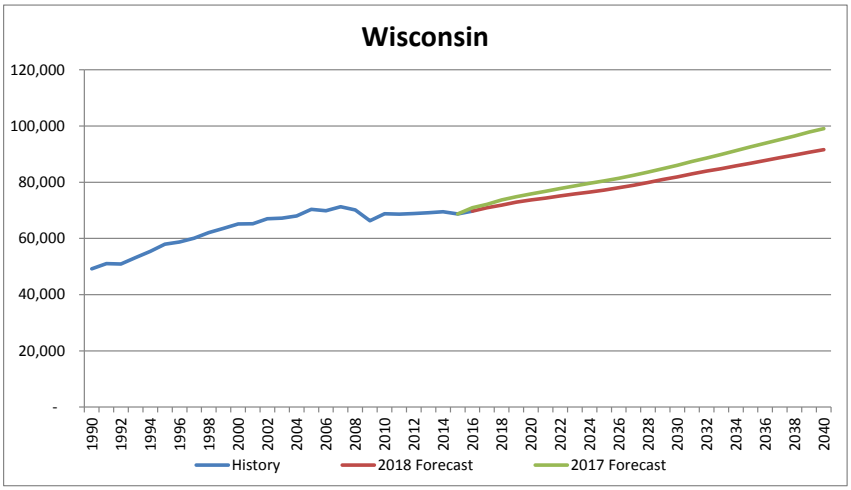
The Wisconsin state econometric model uses real gross state product, real electricity and natural gas prices, cooling degree days, and heating degree days as explanatory variables. Appendix A provides the data sources and model specification. The compound annual growth rates for the drivers are provided in Table 44.

Table 44: Wisconsin Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Real Electricity Price	Real Natural Gas Price	Real Gross State Product
0.09	0.91	1.59

Gross electricity sales are projected to grow at 1.10% in this forecast, which is lower than the 1.36% growth projected in 2017. Figure 19 shows the gross sales projection for the 2017 and 2018 forecasts.

Figure 19: Wisconsin Gross Energy Forecasts (Annual Retail Sales in GWh)



Wisconsin has loads in two LRZs (1 and 2). Unlike the other MISO states, Wisconsin has no non-MISO loads. The Wisconsin gross forecast is allocated to those LRZs based on the historical average of the load fractions, as shown in the Table 45. See Appendix B for more information on the historical load fractions and the process for developing the allocation factors.

Table 45: Wisconsin Allocation Factors (%)

LRZ 1	LRZ 2
16.8	83.2

Annual energy for the LRZs are determined by summing the allocated portions of the appropriate state sales forecasts and benchmarking for the most recent weather normalized metered load energy (as described in Section 2). The resulting forecast growth rates for Wisconsin's LRZs are shown in Table 46. Section 3 contains more information on the LRZ forecasts.

Table 46: Wisconsin LRZ Forecast Compound Annual Growth Rates for the 2019-2038 Period (%)

LRZ	Gross Annual Energy	Net Annual Energy	Gross Summer Peak	Net Summer Peak	Gross Winter Peak	Net Winter Peak
1	0.88	0.76	0.88	0.73	0.88	0.70
2	1.06	0.84	1.06	0.78	1.06	0.70

4 LRZ Forecasts

4.1 ANNUAL LRZ ENERGY FORECASTS

Table 47 provides the gross LRZ annual metered load projections (without the EE adjustments) and Table 48 provides the net LRZ annual metered load projections (with the EE adjustments). There are no EE adjustments for LRZ10 because none were indicated from the data provided by MISO.

Table 47: Gross LRZ Energy Forecasts without EE Adjustments (Annual Metered Load in GWh)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	99,284	65,456	49,513	48,392	38,546	95,637	101,652	38,193	114,903	22,733
2019	100,852	66,381	50,641	48,507	38,632	96,843	102,263	38,774	115,731	23,078
2020	102,387	67,036	51,364	48,634	38,826	97,849	102,663	39,243	116,721	23,460
2021	103,408	67,625	52,394	48,898	38,990	98,865	103,459	39,664	117,182	23,842
2022	104,231	68,300	53,060	49,174	39,046	99,924	103,520	40,106	117,836	24,246
2023	105,288	68,849	53,559	49,405	39,139	101,107	102,852	40,585	118,955	24,652
2024	106,658	69,386	54,196	49,666	39,264	102,307	103,022	41,044	119,742	25,033
2025	107,882	70,032	55,043	49,863	39,456	103,413	103,705	41,483	120,437	25,368
2026	108,955	70,761	55,820	50,098	39,706	104,534	104,412	41,884	121,062	25,682
2027	109,953	71,541	56,521	50,294	39,950	105,614	105,120	42,263	121,630	25,986
2028	110,986	72,389	57,245	50,522	40,132	106,755	105,798	42,703	122,420	26,304
2029	111,974	73,330	58,074	50,771	40,298	107,914	106,591	43,191	123,319	26,640
2030	112,948	74,183	58,888	51,058	40,430	109,046	107,439	43,670	124,276	27,002
2031	113,800	75,107	59,775	51,282	40,517	110,139	108,198	44,133	125,233	27,345
2032	114,445	75,956	60,610	51,554	40,563	111,205	109,037	44,593	126,228	27,681
2033	115,066	76,766	61,338	51,824	40,574	112,279	109,881	45,071	127,232	28,012
2034	115,804	77,583	62,097	52,081	40,575	113,409	110,581	45,575	128,276	28,365
2035	116,621	78,407	62,958	52,337	40,602	114,544	111,477	46,100	129,348	28,739
2036	117,485	79,288	63,826	52,591	40,642	115,726	112,330	46,656	130,421	29,113
2037	118,312	80,162	64,701	52,877	40,702	116,915	113,131	47,203	131,592	29,488
2038	119,131	81,032	65,575	53,145	40,771	118,109	113,950	47,767	132,728	29,859
Compound Annual Growth Rates (%)										
2019-2023	1.08	0.92	1.41	0.46	0.33	1.08	0.14	1.15	0.69	1.66
2019-2028	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
2019-2038	0.88	1.06	1.37	0.48	0.28	1.05	0.57	1.10	0.72	1.37

LRZ FORECASTS

Table 48: Net LRZ Energy Forecasts with EE Adjustments (Annual Metered Load in GWh)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	99,155	65,205	49,180	48,199	38,497	95,554	101,505	38,036	114,849	22,733
2019	100,604	65,876	49,967	48,082	38,532	96,685	101,951	38,457	115,645	23,078
2020	102,015	66,275	50,346	47,982	38,651	97,613	102,186	38,765	116,598	23,460
2021	102,915	66,610	51,106	48,019	38,730	98,556	102,815	39,024	117,020	23,842
2022	103,615	67,034	51,497	48,065	38,693	99,545	102,709	39,305	117,633	24,246
2023	104,546	67,334	51,716	48,066	38,691	100,660	101,868	39,622	118,711	24,652
2024	105,789	67,626	52,074	48,096	38,720	101,792	101,864	39,920	119,458	25,033
2025	106,883	68,030	52,655	48,061	38,825	102,832	102,379	40,199	120,112	25,368
2026	107,825	68,523	53,161	48,127	38,990	103,889	102,920	40,440	120,695	25,682
2027	108,690	69,071	53,589	48,210	39,146	104,907	103,461	40,662	121,221	25,986
2028	109,588	69,690	54,037	48,326	39,247	105,988	103,973	40,945	121,968	26,304
2029	110,439	70,409	54,598	48,469	39,337	107,088	104,603	41,277	122,823	26,640
2030	111,277	71,044	55,140	48,650	39,393	108,163	105,285	41,600	123,737	27,002
2031	111,991	71,887	55,752	48,769	39,402	109,200	105,874	41,908	124,649	27,345
2032	112,495	72,658	56,307	48,936	39,370	110,211	106,540	42,215	125,600	27,681
2033	112,972	73,389	56,751	49,099	39,300	111,232	107,211	42,540	126,559	28,012
2034	113,563	74,128	57,256	49,250	39,218	112,308	107,729	42,892	127,557	28,365
2035	114,228	74,872	57,859	49,401	39,161	113,391	108,439	43,266	128,582	28,739
2036	114,940	75,674	58,468	49,549	39,113	114,522	109,102	43,674	129,609	29,113
2037	115,610	76,470	59,081	49,730	39,085	115,661	109,712	44,073	130,733	29,488
2038	116,275	77,268	59,697	49,899	39,067	116,808	110,339	44,497	131,823	29,859
Compound Annual Growth Rates (%)										
2019-2023	0.97	0.55	0.86	-0.01	0.10	1.01	-0.02	0.75	0.66	1.66
2019-2028	0.95	0.63	0.87	0.06	0.20	1.03	0.22	0.70	0.59	1.46
2019-2038	0.76	0.84	0.94	0.20	0.07	1.00	0.42	0.77	0.69	1.37

4.2 LRZ NON-COINCIDENT PEAK DEMANDS

The LRZ-level non-coincident[6] summer and winter peak demands were calculated by applying the energy-to-peak conversion factors to the LRZ annual metered load projections. These values represent the projected peak demands for the summer and winter under normal weather conditions. Usually, the non-coincident peak of each LRZ does not occur at the same time when the MISO reaches system-wide peak. The EE adjustments were made directly on non-coincident peak projections. Table 49 to Table 52 provide gross and net (without and with EE adjustments) non-coincident peak demand projections for summer and winter.

Table 49: Summer Non-Coincident Peak Demand without EE Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,741	12,397	9,383	9,477	7,850	16,580	20,704	7,815	20,872	4,743
2019	18,021	12,572	9,597	9,500	7,868	16,789	20,828	7,933	21,022	4,815
2020	18,295	12,696	9,734	9,525	7,907	16,964	20,910	8,029	21,202	4,895
2021	18,478	12,808	9,929	9,576	7,941	17,140	21,072	8,115	21,286	4,975
2022	18,625	12,936	10,055	9,630	7,952	17,323	21,084	8,206	21,405	5,059
2023	18,814	13,040	10,150	9,676	7,971	17,529	20,948	8,304	21,608	5,144
2024	19,059	13,141	10,271	9,727	7,997	17,737	20,983	8,398	21,751	5,223
2025	19,277	13,264	10,431	9,765	8,036	17,928	21,122	8,488	21,877	5,293
2026	19,469	13,402	10,578	9,811	8,086	18,123	21,266	8,570	21,991	5,359
2027	19,647	13,549	10,711	9,850	8,136	18,310	21,410	8,647	22,094	5,422
2028	19,832	13,710	10,848	9,894	8,173	18,508	21,548	8,737	22,237	5,489
2029	20,008	13,888	11,006	9,943	8,207	18,709	21,710	8,837	22,401	5,559
2030	20,183	14,050	11,160	9,999	8,234	18,905	21,883	8,935	22,575	5,634
2031	20,335	14,225	11,328	10,043	8,252	19,094	22,037	9,030	22,748	5,706
2032	20,450	14,386	11,486	10,097	8,261	19,279	22,208	9,124	22,929	5,776
2033	20,561	14,539	11,624	10,149	8,263	19,466	22,380	9,222	23,112	5,845
2034	20,693	14,694	11,768	10,200	8,263	19,661	22,523	9,325	23,301	5,919
2035	20,839	14,850	11,931	10,250	8,269	19,858	22,705	9,432	23,496	5,997
2036	20,993	15,017	12,096	10,300	8,277	20,063	22,879	9,546	23,691	6,075
2037	21,141	15,182	12,262	10,356	8,289	20,269	23,042	9,658	23,904	6,153
2038	21,287	15,347	12,427	10,408	8,303	20,476	23,209	9,773	24,110	6,230
Compound Annual Growth Rates (%)										
2019-2023	1.08	0.92	1.41	0.46	0.33	1.08	0.14	1.15	0.69	1.66
2019-2028	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
2019-2038	0.88	1.06	1.37	0.48	0.28	1.05	0.57	1.10	0.72	1.37

[6] Non-coincident from the perspective of the MISO system peak load.

LRZ FORECASTS

Table 50: Winter Non-Coincident Peak Demand without EE Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	15,031	9,551	7,431	7,537	6,583	14,956	14,730	6,509	18,309	4,065
2019	15,269	9,686	7,600	7,555	6,597	15,145	14,818	6,608	18,441	4,127
2020	15,501	9,782	7,709	7,574	6,631	15,302	14,876	6,688	18,598	4,195
2021	15,655	9,868	7,863	7,616	6,659	15,461	14,991	6,759	18,672	4,263
2022	15,780	9,966	7,963	7,658	6,668	15,626	15,000	6,835	18,776	4,336
2023	15,940	10,046	8,038	7,694	6,684	15,811	14,904	6,916	18,954	4,408
2024	16,148	10,125	8,134	7,735	6,705	15,999	14,928	6,994	19,080	4,476
2025	16,333	10,219	8,261	7,766	6,738	16,172	15,027	7,069	19,191	4,536
2026	16,495	10,325	8,377	7,802	6,781	16,347	15,130	7,138	19,290	4,593
2027	16,646	10,439	8,483	7,833	6,822	16,516	15,232	7,202	19,381	4,647
2028	16,803	10,563	8,591	7,868	6,854	16,695	15,330	7,277	19,507	4,704
2029	16,952	10,700	8,716	7,907	6,882	16,876	15,445	7,360	19,650	4,764
2030	17,100	10,825	8,838	7,952	6,904	17,053	15,568	7,442	19,802	4,829
2031	17,229	10,959	8,971	7,987	6,919	17,224	15,678	7,521	19,955	4,890
2032	17,327	11,083	9,096	8,029	6,927	17,391	15,800	7,599	20,113	4,950
2033	17,421	11,202	9,206	8,071	6,929	17,559	15,922	7,681	20,273	5,009
2034	17,532	11,321	9,320	8,111	6,929	17,735	16,023	7,767	20,440	5,072
2035	17,656	11,441	9,449	8,151	6,934	17,913	16,153	7,856	20,610	5,139
2036	17,787	11,570	9,579	8,191	6,941	18,098	16,277	7,951	20,781	5,206
2037	17,912	11,697	9,710	8,235	6,951	18,284	16,393	8,044	20,968	5,273
2038	18,036	11,824	9,842	8,277	6,963	18,470	16,512	8,140	21,149	5,340
Compound Annual Growth Rates (%)										
2019-2023	1.08	0.92	1.41	0.46	0.33	1.08	0.14	1.15	0.69	1.66
2019-2028	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
2019-2038	0.88	1.06	1.37	0.48	0.28	1.05	0.57	1.10	0.72	1.37

LRZ FORECASTS

Table 51: Summer Non-Coincident Peak Demand with EE Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,711	12,337	9,306	9,432	7,837	16,560	20,668	7,780	20,859	4,743
2019	17,963	12,451	9,441	9,399	7,841	16,750	20,753	7,864	21,002	4,815
2020	18,208	12,513	9,498	9,370	7,861	16,905	20,795	7,925	21,173	4,895
2021	18,362	12,563	9,631	9,368	7,873	17,063	20,916	7,975	21,248	4,975
2022	18,480	12,631	9,693	9,368	7,860	17,229	20,888	8,031	21,357	5,059
2023	18,640	12,675	9,723	9,359	7,854	17,417	20,711	8,093	21,550	5,144
2024	18,854	12,718	9,780	9,355	7,854	17,608	20,703	8,152	21,684	5,223
2025	19,043	12,782	9,879	9,339	7,870	17,784	20,802	8,207	21,800	5,293
2026	19,204	12,863	9,963	9,345	7,899	17,962	20,906	8,254	21,904	5,359
2027	19,351	12,954	10,033	9,357	7,926	18,134	21,010	8,297	21,997	5,422
2028	19,504	13,060	10,107	9,375	7,941	18,316	21,108	8,352	22,130	5,489
2029	19,648	13,184	10,202	9,399	7,955	18,503	21,230	8,418	22,283	5,559
2030	19,790	13,293	10,293	9,430	7,962	18,685	21,363	8,482	22,447	5,634
2031	19,910	13,449	10,398	9,449	7,959	18,860	21,477	8,543	22,610	5,706
2032	19,993	13,590	10,492	9,478	7,948	19,031	21,606	8,604	22,780	5,776
2033	20,070	13,725	10,564	9,506	7,929	19,204	21,736	8,668	22,952	5,845
2034	20,167	13,860	10,650	9,531	7,907	19,387	21,835	8,738	23,131	5,919
2035	20,278	13,997	10,754	9,557	7,890	19,571	21,972	8,812	23,314	5,997
2036	20,397	14,144	10,860	9,582	7,875	19,763	22,100	8,894	23,498	6,075
2037	20,508	14,291	10,966	9,613	7,864	19,956	22,217	8,973	23,700	6,153
2038	20,617	14,437	11,071	9,641	7,854	20,151	22,337	9,057	23,895	6,230
Compound Annual Growth Rates (%)										
2019-2023	0.93	0.45	0.74	-0.11	0.04	0.98	-0.05	0.72	0.65	1.66
2019-2028	0.92	0.53	0.76	-0.03	0.14	1.00	0.19	0.67	0.58	1.46
2019-2038	0.73	0.78	0.84	0.13	0.01	0.98	0.39	0.75	0.68	1.37

LRZ FORECASTS

Table 52: Winter Non-Coincident Peak Demand with EE Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	15,001	9,491	7,354	7,491	6,570	14,935	14,694	6,474	18,296	4,065
2019	15,210	9,565	7,444	7,454	6,571	15,105	14,743	6,538	18,421	4,127
2020	15,414	9,599	7,473	7,420	6,585	15,243	14,761	6,583	18,570	4,195
2021	15,540	9,624	7,565	7,407	6,590	15,384	14,836	6,619	18,634	4,263
2022	15,635	9,662	7,601	7,396	6,576	15,532	14,804	6,659	18,728	4,336
2023	15,766	9,682	7,611	7,378	6,567	15,700	14,666	6,706	18,897	4,408
2024	15,943	9,701	7,643	7,363	6,563	15,871	14,649	6,749	19,013	4,476
2025	16,098	9,737	7,708	7,339	6,573	16,027	14,707	6,788	19,114	4,536
2026	16,230	9,786	7,762	7,336	6,593	16,186	14,769	6,822	19,203	4,593
2027	16,350	9,844	7,805	7,340	6,612	16,340	14,832	6,852	19,284	4,647
2028	16,475	9,913	7,849	7,349	6,622	16,503	14,890	6,892	19,399	4,704
2029	16,592	9,996	7,912	7,363	6,630	16,670	14,965	6,941	19,532	4,764
2030	16,708	10,068	7,971	7,383	6,632	16,833	15,048	6,989	19,675	4,829
2031	16,804	10,183	8,041	7,393	6,627	16,990	15,118	7,034	19,817	4,890
2032	16,869	10,288	8,102	7,410	6,614	17,143	15,198	7,079	19,964	4,950
2033	16,929	10,387	8,146	7,428	6,594	17,297	15,278	7,127	20,114	5,009
2034	17,007	10,487	8,202	7,443	6,573	17,461	15,336	7,180	20,269	5,072
2035	17,095	10,588	8,272	7,458	6,555	17,625	15,420	7,236	20,429	5,139
2036	17,190	10,697	8,343	7,473	6,539	17,797	15,498	7,299	20,589	5,206
2037	17,279	10,806	8,415	7,493	6,525	17,971	15,568	7,360	20,765	5,273
2038	17,366	10,914	8,485	7,510	6,513	18,145	15,640	7,424	20,934	5,340
Compound Annual Growth Rates (%)										
2019-2023	0.90	0.30	0.56	-0.26	-0.02	0.97	-0.13	0.63	0.64	1.66
2019-2028	0.89	0.40	0.59	-0.16	0.09	0.99	0.11	0.59	0.58	1.46
2019-2038	0.70	0.70	0.69	0.04	-0.05	0.97	0.31	0.67	0.68	1.37

4.3 LRZ Forecasts

4.3.1 LRZ 1

LRZ 1 consists of most of the state of Minnesota; parts of Montana, North Dakota, South Dakota, and Wisconsin; and small portions of Iowa, Illinois, and Michigan. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Minneapolis-St. Paul, MN according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 0.88% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.76%. These are lower than the rates in the 2017 Forecast Update (1.45% and 1.34%, respectively). Figure 20 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 21 provides similar information for non-coincident summer peak demand.

Figure 20: Gross and Net LRZ1 Energy (GWh)

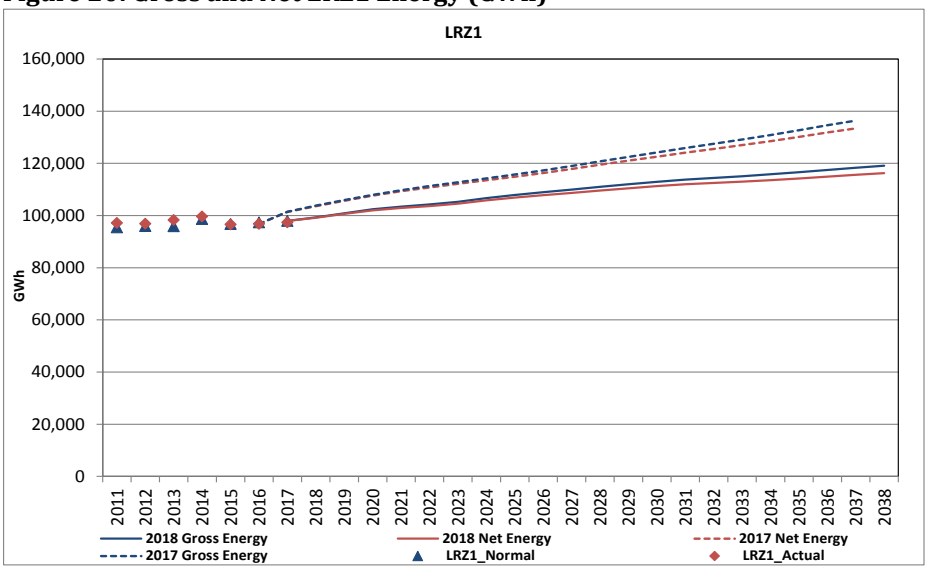
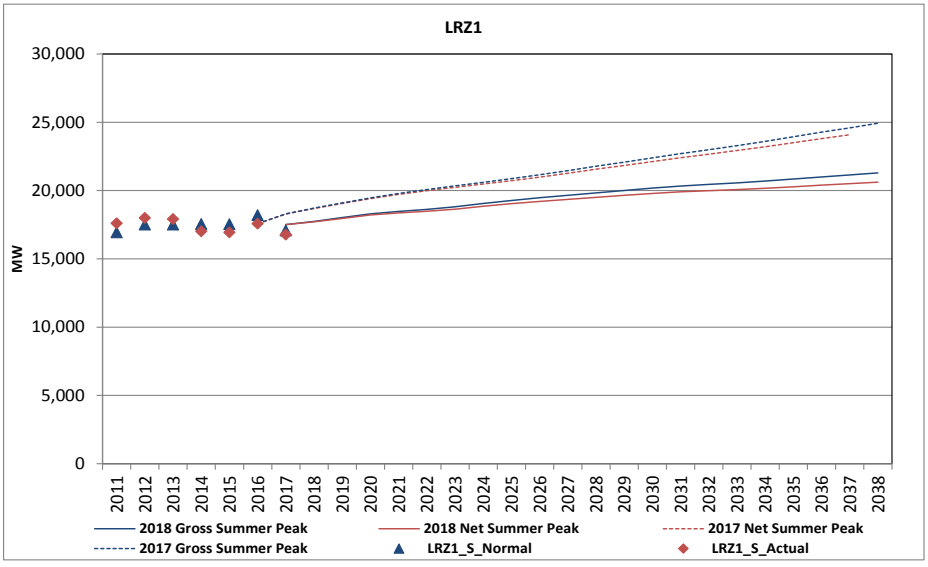


Figure 21: Gross and Net LRZ1 Summer Non-Coincident Peak Demand (MW)



4.3.2 LRZ 2

LRZ 2 is made up of most of the state of Wisconsin and part of Michigan. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Milwaukee, WI according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 1.06% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.84%. These are lower than the rates in the 2017 Forecast Update (1.32% for both gross and net). Figure 22 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 23 provides similar information for non-coincident summer peak demand.

Figure 22: Gross and Net LRZ2 Energy (GWh)

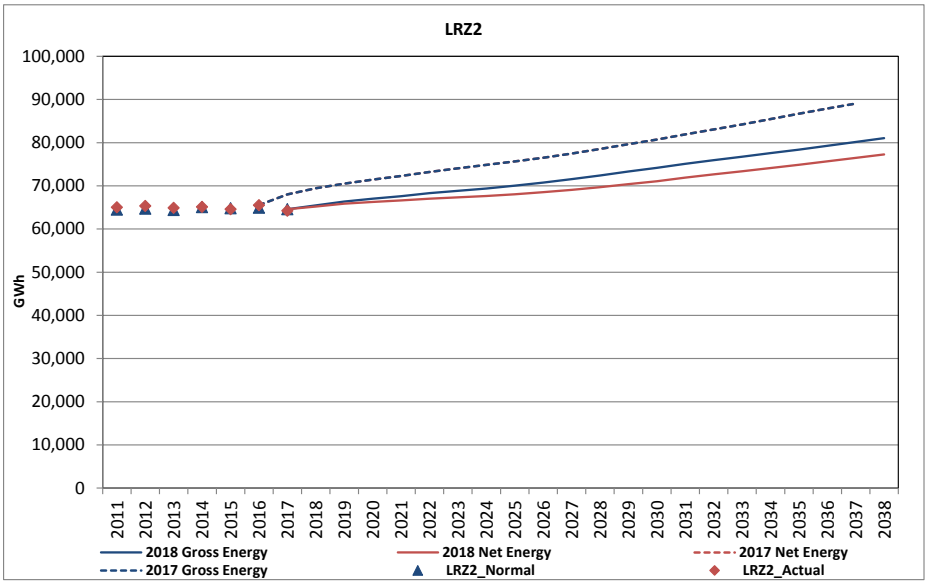
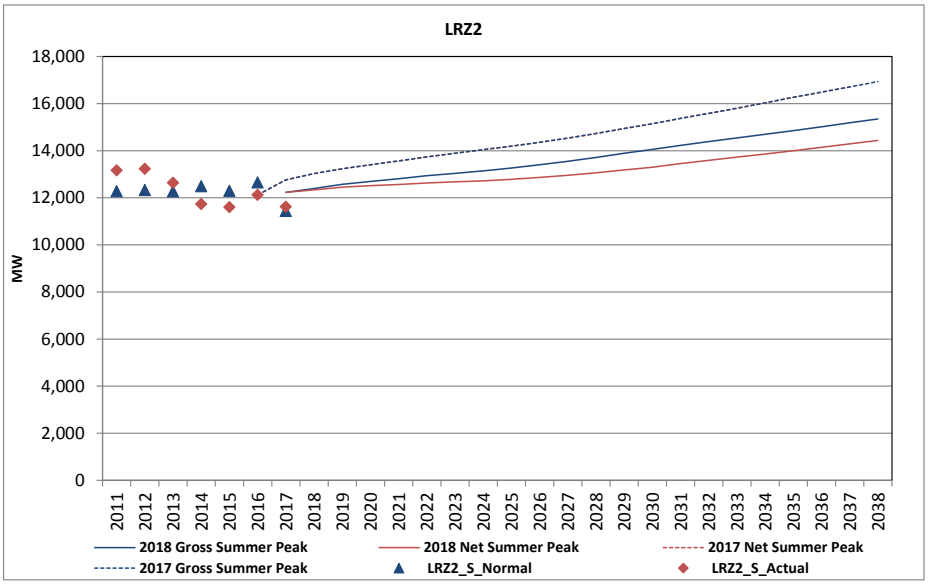


Figure 23: Gross and Net LRZ2 Summer Non-Coincident Peak Demand (MW)



4.3.3 LRZ 3

LRZ 3 consists of most of the state of Iowa and small portions of Illinois, Minnesota, and South Dakota. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Des Moines, IA according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 1.37% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.94%. These are somewhat lower than the rates in the 2017 Forecast Update (1.51% and 1.18%, respectively), but the long-term forecasts are similar due to a small difference in the starting point. Figure 24 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 25 provides similar information for non-coincident summer peak demand.

Figure 24: Gross and Net LRZ3 Energy (GWh)

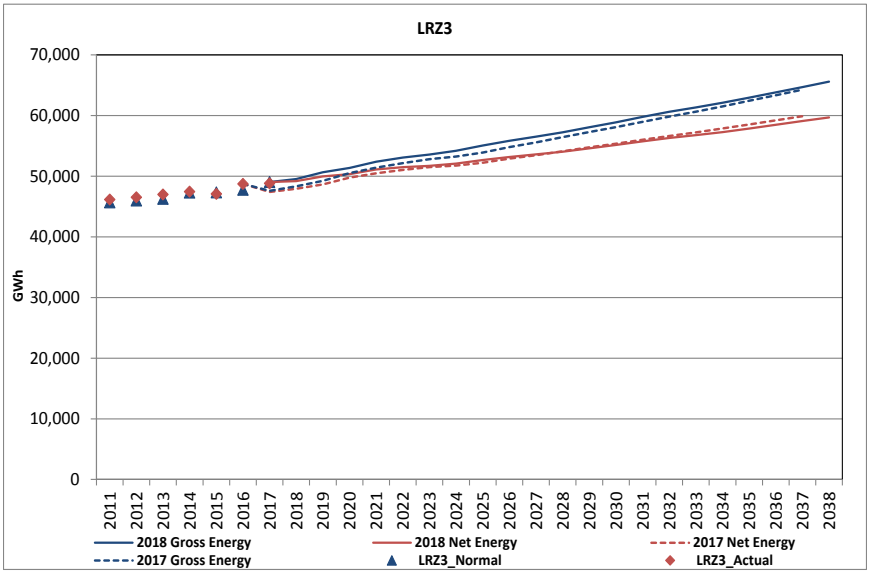
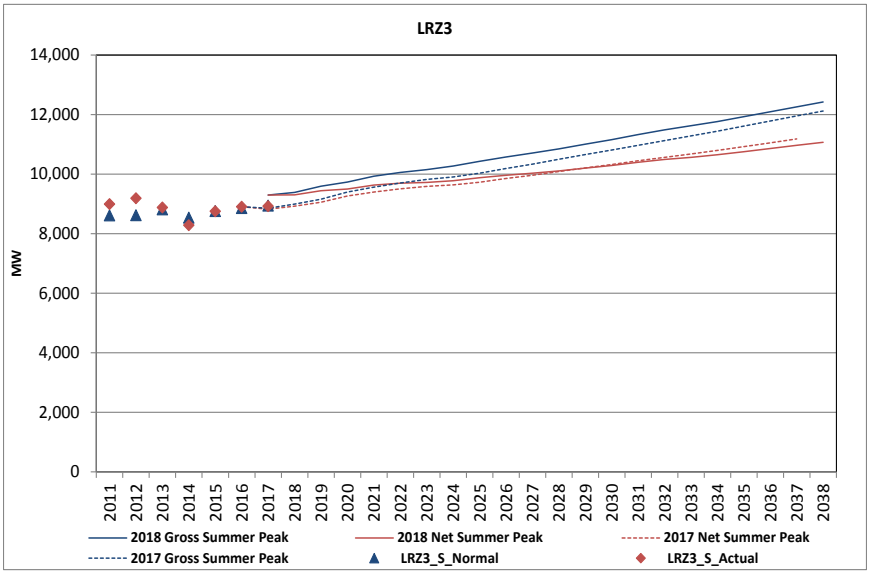


Figure 25: Gross and Net LRZ3 Summer Non-Coincident Peak Demand (MW)



4.3.4 LRZ 4

LRZ 4 consists of about 1/3 of the state of Illinois. The annual energy forecast for the LRZ is determined from that state's forecast using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Springfield, IL according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 0.48% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.20%. These are slightly lower than the rates in the 2017 Forecast Update (0.51% and 0.31%, respectively). Since the current forecast starts at a lower point, the forecast trajectories lie below those from the 2017 forecast. Figure 26 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 27 provides similar information for non-coincident summer peak demand.

Figure 26: Gross and Net LRZ4 Energy (GWh)

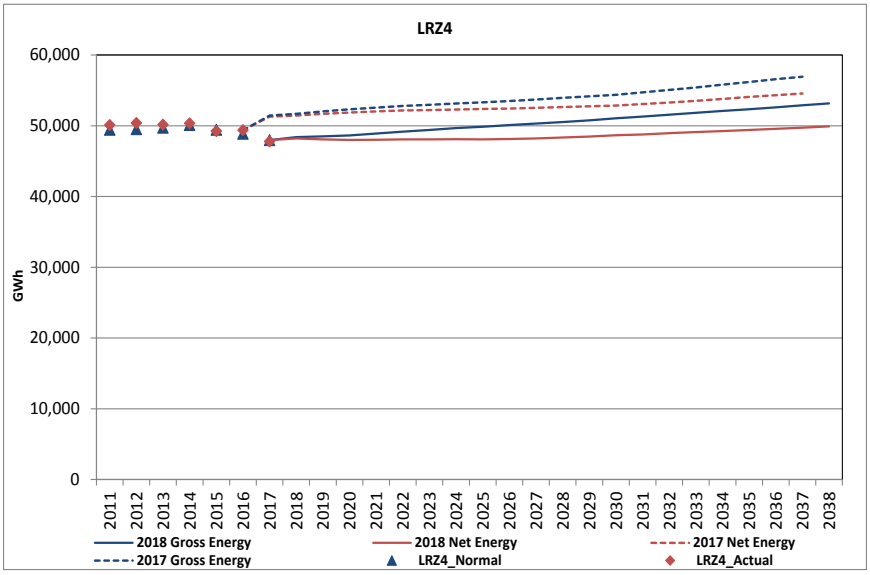
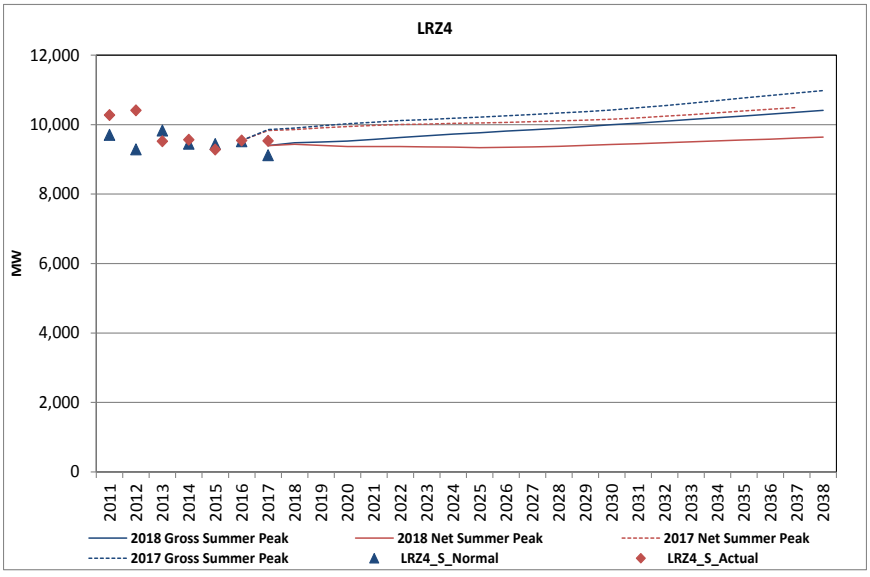


Figure 27: Gross and Net LRZ4 Summer Non-Coincident Peak Demand (MW)



4.3.5 LRZ 5

LRZ 5 consists of about half of the state of Missouri. The annual energy forecast for the LRZ is determined from that state's forecast using the allocation method described in Appendix B. Due to differences in economic projections between the state and the St. Louis Metropolitan Statistical Area, the allocation factor declines somewhat over time. Non-coincident summer and winter peak demands are determined using weather information for St. Louis, MO according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 0.28% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.07%. These are lower than the rates in the 2017 Forecast Update (0.81% and 0.64%, respectively). Figure 28 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 29 provides similar information for non-coincident summer peak demand.

Figure 28: Gross and Net LRZ5 Energy (GWh)

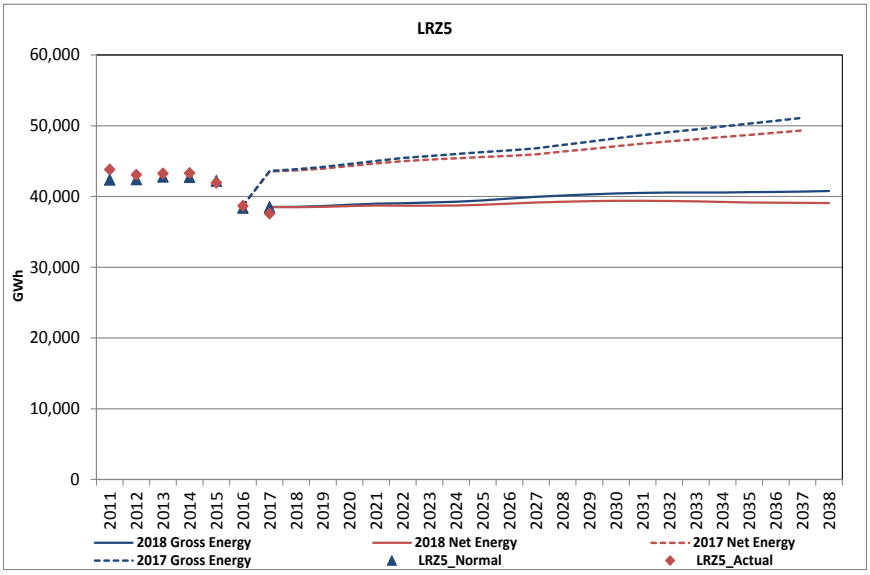
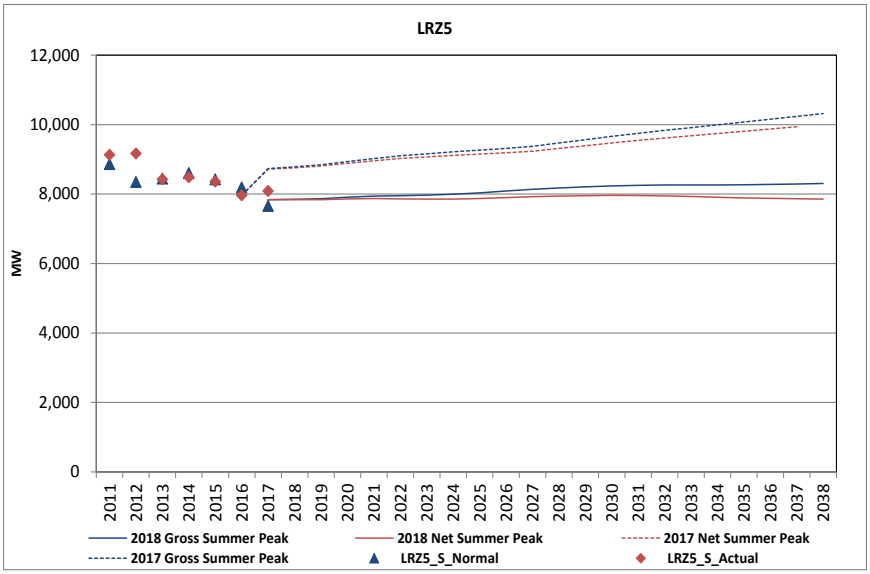


Figure 29: Gross and Net LRZ5 Summer Non-Coincident Peak Demand (MW)



4.3.6 LRZ 6

LRZ 6 is made up of portions of the states of Indiana and Kentucky. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Indianapolis, IN according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 1.05% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 1.00%. These are slightly lower than the rates in the 2017 Forecast Update (1.12% and 1.03%, respectively). Since the current forecast starts at a lower point, the forecast trajectories lie below those from the 2017 forecast. Figure 30 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 31 provides similar information for non-coincident summer peak demand.

Figure 30: Gross and Net LRZ6 Energy (GWh)

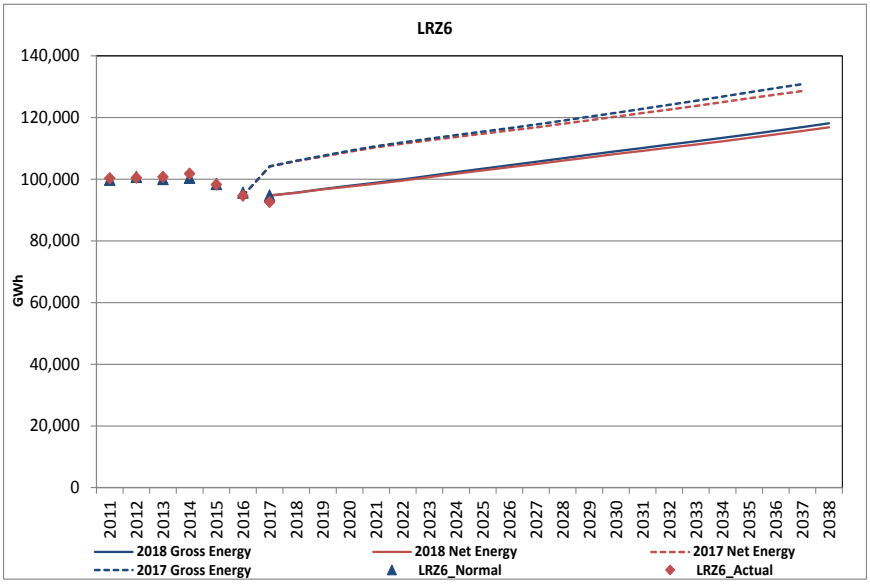
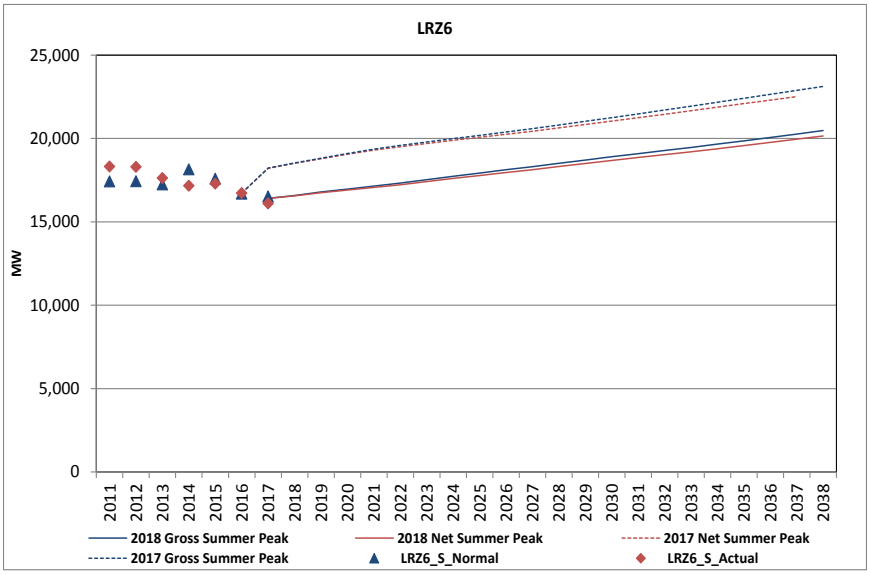


Figure 31: Gross and Net LRZ6 Summer Non-Coincident Peak Demand (MW)



4.3.7 LRZ 7

LRZ 7 consists of most of the state of Michigan. The annual energy forecast for the LRZ is determined from that state's forecast using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Lansing, MI according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 0.57% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.42%. These are lower than the rates in the 2017 Forecast Update (0.88% and 0.76%, respectively). Figure 32 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 33 provides similar information for non-coincident summer peak demand.

Figure 32: Gross and Net LRZ7 Energy (GWh)

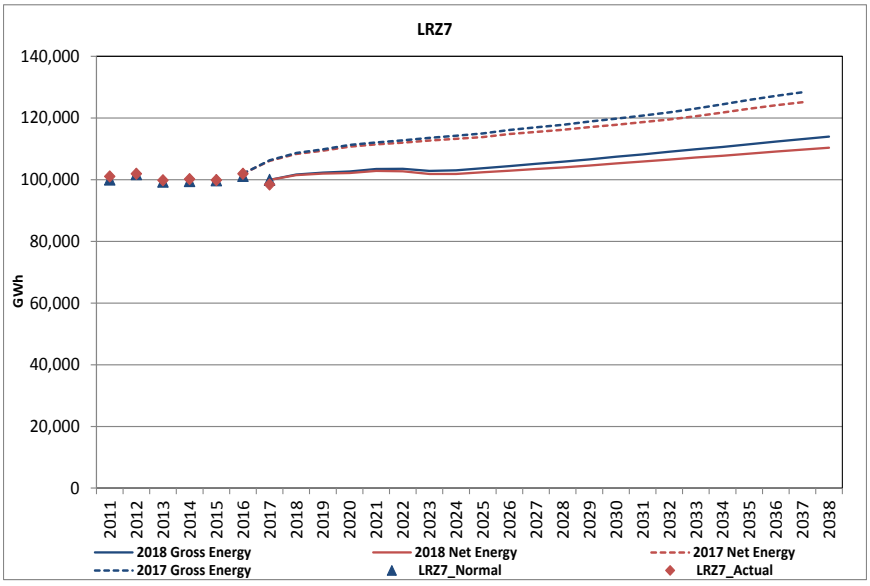
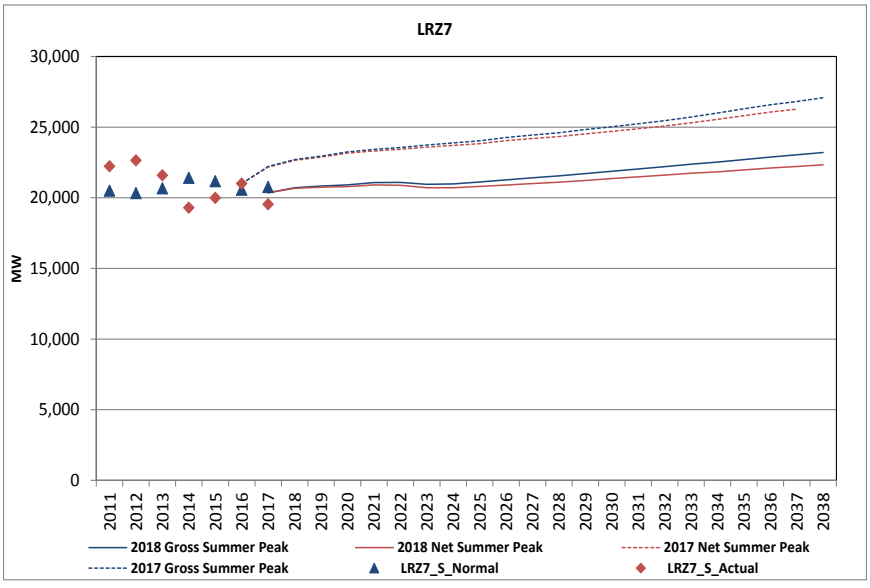


Figure 33: Gross and Net LRZ7 Summer Non-Coincident Peak Demand (MW)



4.3.8 LRZ 8

LRZ 8 consists of most of the state of Arkansas and small portions of Missouri and Texas. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Little Rock, AR according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 1.15% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.77%. While the gross forecast rate is slightly higher, the net forecast rate is lower than the rates in the 2017 Forecast Update (1.06% and 1.05%, respectively). Figure 34 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 35 provides similar information for non-coincident summer peak demand.

Figure 34: Gross and Net LRZ8 Energy (GWh)

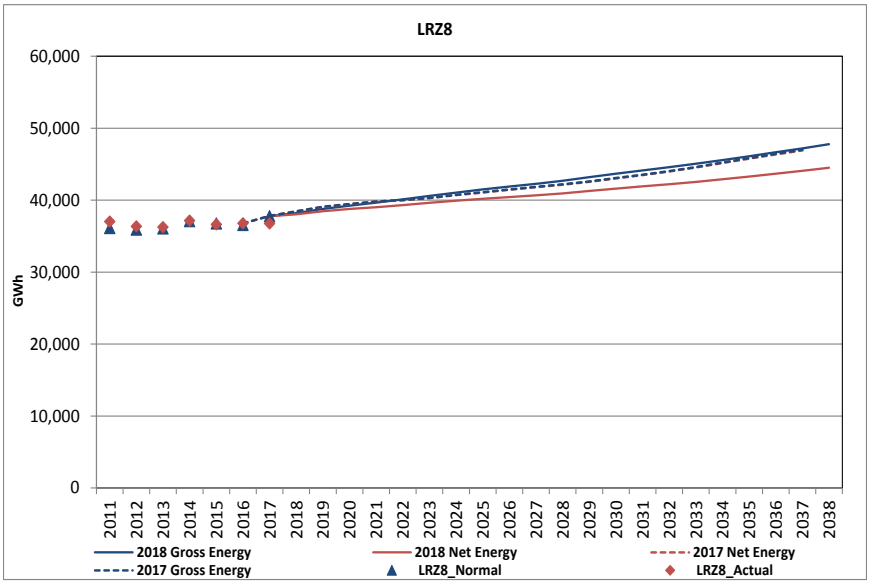
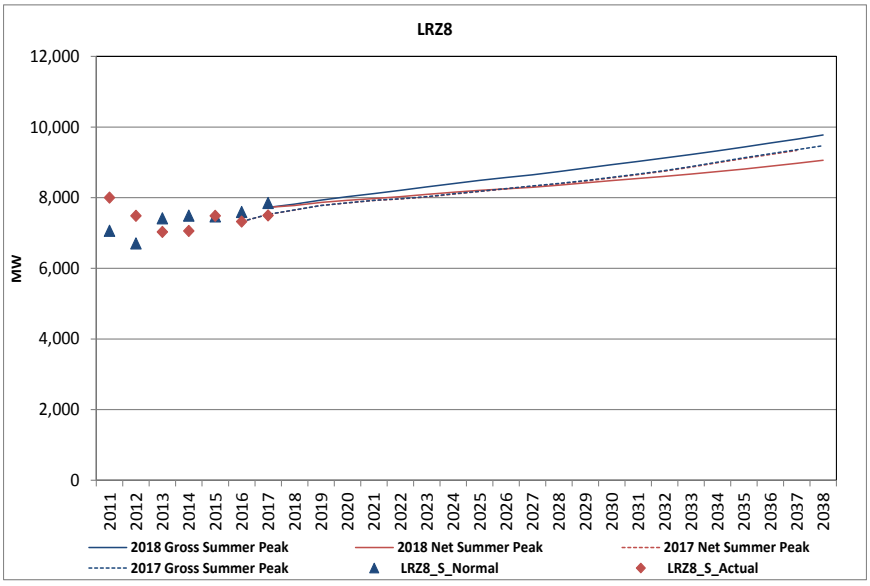


Figure 35: Gross and Net LRZ8 Summer Non-Coincident Peak Demand (MW)



4.3.9 LRZ 9

LRZ 9 consists of most of the state of Louisiana and a small portion of Texas. The annual energy forecast for the LRZ is determined from those states' forecasts using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Lake Charles, LA according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 0.72% for the period from 2019 to 2038. The growth rate after adjusting for energy efficiency programs is 0.69%. These are lower than the rates in the 2017 Forecast Update (1.05% and 0.99%, respectively). Since the current forecast starts at a higher point, the forecast trajectories lie above those from the 2017 forecast. Figure 36 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 37 provides similar information for non-coincident summer peak demand.

Figure 36: Gross and Net LRZ9 Energy (GWh)

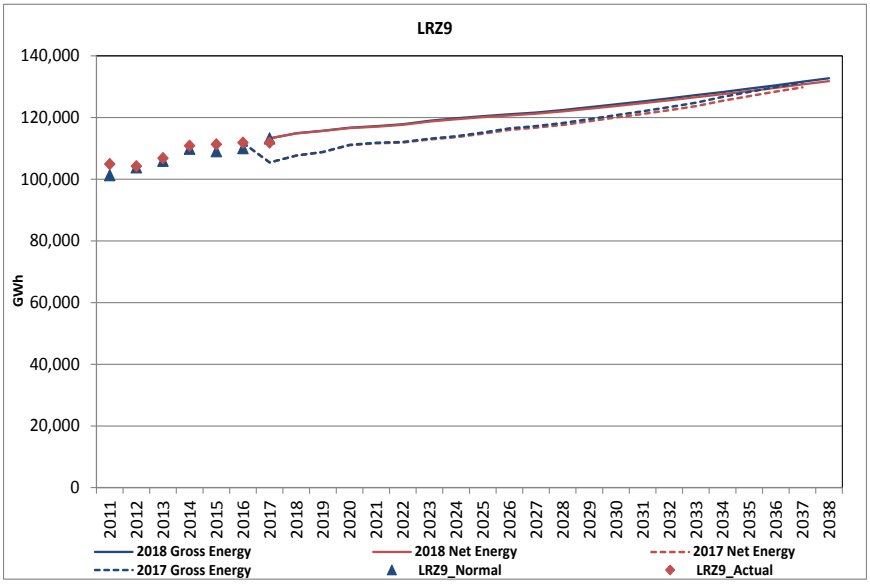
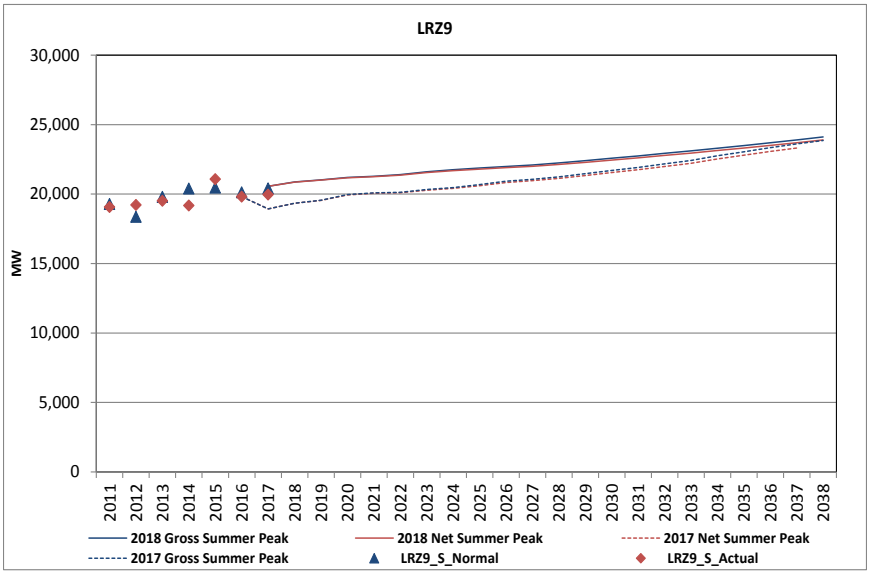


Figure 37: Gross and Net LRZ9 Summer Non-Coincident Peak Demand (MW)



4.3.10 LRZ 10

LRZ 10 consists of almost half of the state of Mississippi. The annual energy forecast for the LRZ is determined from that state's forecast using the allocation method described in Appendix B. Non-coincident summer and winter peak demands are determined using weather information for Jackson, MS according to the methodology described in Appendix C.

Gross annual energy is projected to grow at a compound annual growth rate of 1.37% for the period from 2019 to 2038. Since no energy efficiency programs were chosen in LRZ 10, the net forecast is identical to the gross forecast. The growth rate is lower than in the 2017 Forecast Update (1.46%). Figure 38 shows the current and previous annual energy forecasts along with actual and weather-normalized historical values. Figure 39 provides similar information for non-coincident summer peak demand.

Figure 38: Gross and Net LRZ10 Energy (GWh)

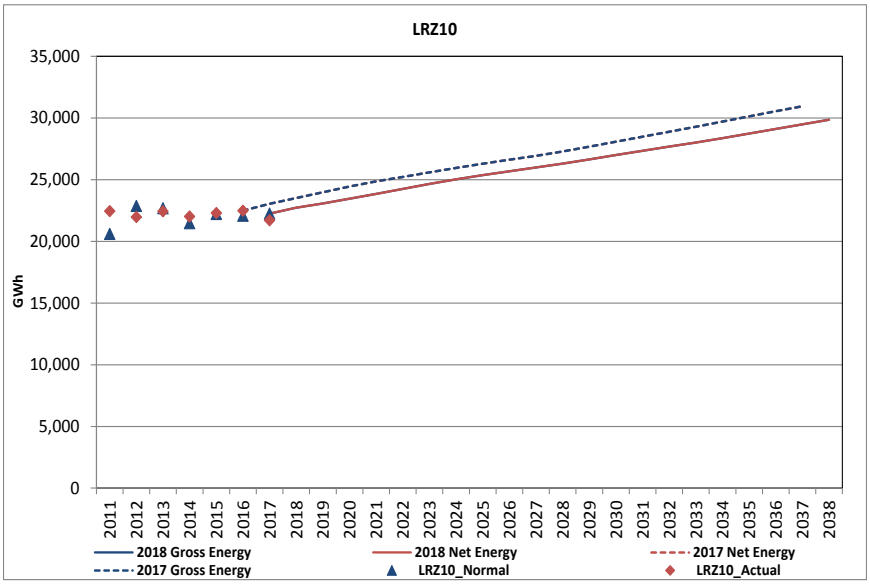
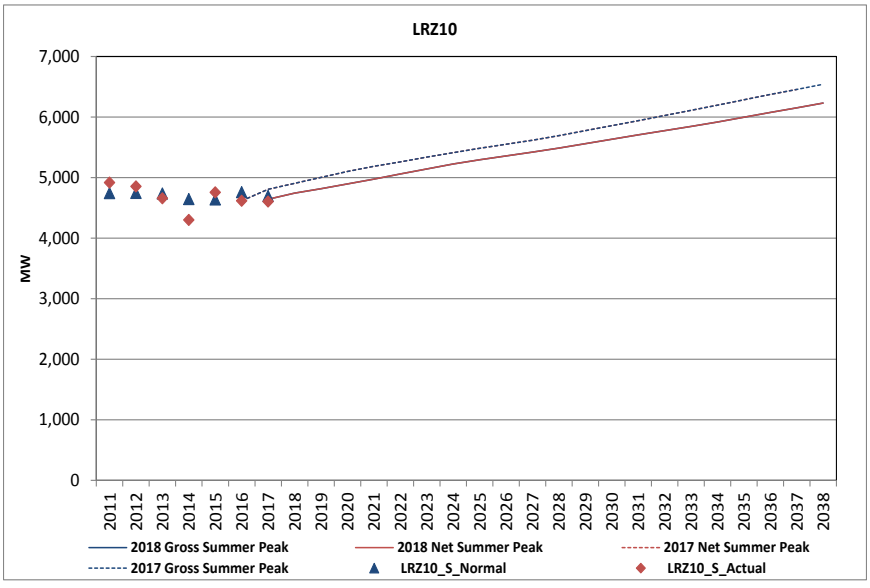


Figure 39: Gross and Net LRZ10 Summer Non-Coincident Peak Demand (MW)



5 MISO Forecasts

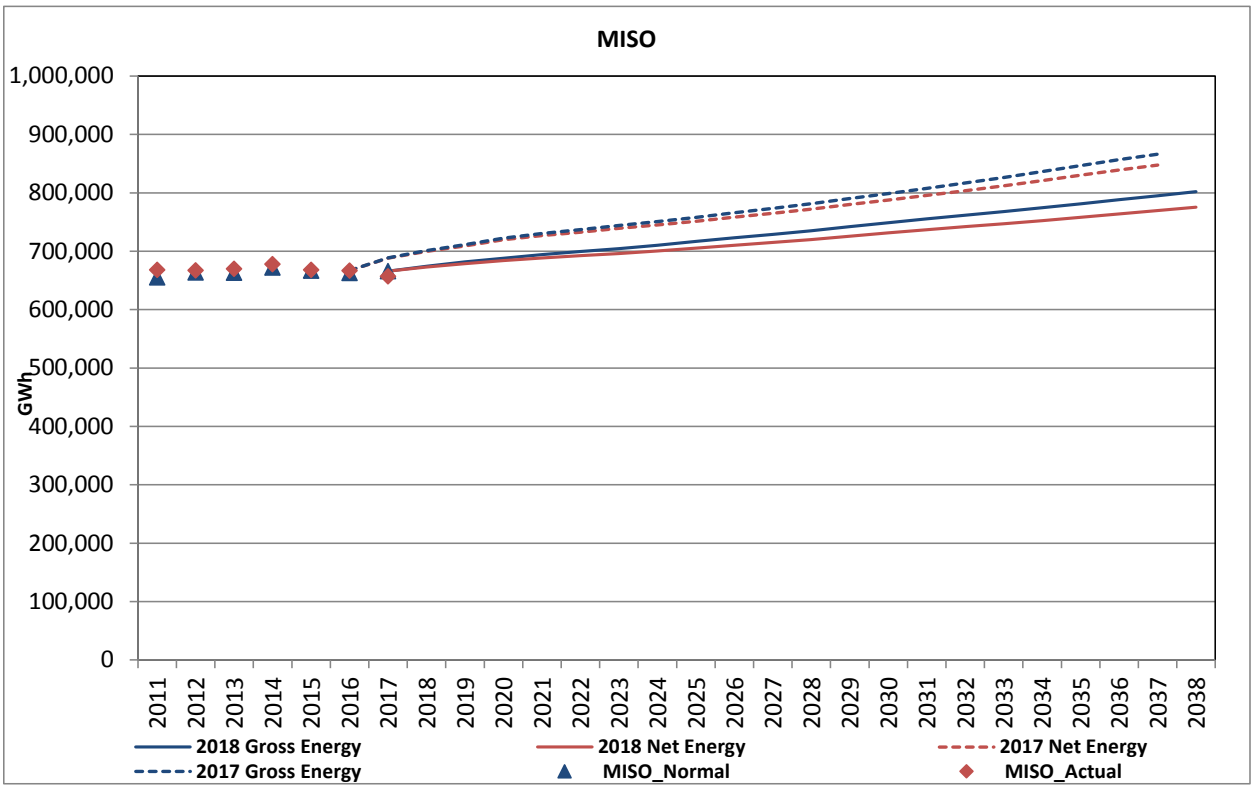
5.1 MISO ANNUAL ENERGY FORECAST

The MISO annual energy forecast is found by summing the individual LRZ metered load forecasts. Table 53 and Figure 40 provide the MISO-level energy forecast. Please note the forecasts are for the specified calendar year, not the MISO planning year. The 20-year growth rates for the gross (0.86%) and net (0.70%) forecasts are lower than those in the 2017 forecast (1.12% and 1.00%, respectively).

Table 53: Gross and Net MISO System Energy (Annual Metered Load in GWh)

Year	MISO Energy without EE Adjustments	MISO Energy with EE Adjustments
2017	665,862	665,862
2018	674,309	672,912
2019	681,704	678,878
2020	688,182	683,890
2021	694,326	688,635
2022	699,444	692,340
2023	704,392	695,866
2024	710,318	700,372
2025	716,682	705,345
2026	722,914	710,253
2027	728,871	714,942
2028	735,253	720,065
2029	742,101	725,682
2030	748,940	731,291
2031	755,529	736,778
2032	761,872	742,011
2033	768,042	747,064
2034	774,346	752,265
2035	781,133	757,939
2036	788,079	763,764
2037	795,085	769,644
2038	802,068	775,531
Compound Annual Growth Rates (%)		
2019-2023	0.82	0.62
2019-2028	0.84	0.66
2019-2038	0.86	0.70

Figure 40: Gross and Net MISO System Energy Forecast (Metered Load in GWh)



5.2 MISO SYSTEM COINCIDENT PEAK DEMAND FORECAST

Not all LRZs experience their peak demands at the same time. This load diversity means that the MISO system peak demand level is less than the arithmetic sum of the LRZ non-coincident peak demands. The MISO system coincident peak demand is determined by applying coincidence factors to individual LRZ non-coincident peak demands and summing. These coincidence factors represent the ratio of the LRZ's load at the time of the overall MISO system peak to the LRZ's non-coincident peak. Coincidence factors were calculated from hourly loads over the 2010 to 2017 timeframe. Table 54 and Table 55 list the summer and winter coincidence factors. When the coincidence factor equals 1, it means the peak for that zone coincides with the MISO system-wide peak. Table 56 and Figure 41 provide the MISO system seasonal peak demand forecasts with and without EE adjustments.

Table 54: MISO Coincident Factors—Summer

	Summer Coincident Factor								
LRZ	Average	2010	2011	2012	2013	2014	2015	2016	2017
1	0.945	0.968	1.000	0.945	0.973	0.896	0.891	0.951	0.933
2	0.979	0.948	1.000	0.969	0.999	1.000	0.950	0.977	0.992
3	0.964	0.952	0.986	0.974	0.969	0.992	0.848	0.997	0.997
4	0.971	1.000	0.988	0.945	0.988	0.885	0.976	0.999	0.989
5	0.972	1.000	0.971	0.949	0.963	0.907	0.999	0.993	0.997
6	0.980	0.968	0.991	0.973	1.000	0.970	0.995	0.950	0.990
7	0.962	0.913	0.961	1.000	0.999	0.998	1.000	0.863	0.960
8	0.946	0.964	0.936	0.929	0.936	0.875	0.950	0.981	0.995
9	0.940	0.982	0.917	0.912	0.860	0.920	0.937	0.996	0.997
10	0.918	0.960	0.901	0.894	0.791	0.844	0.968	0.988	1.000

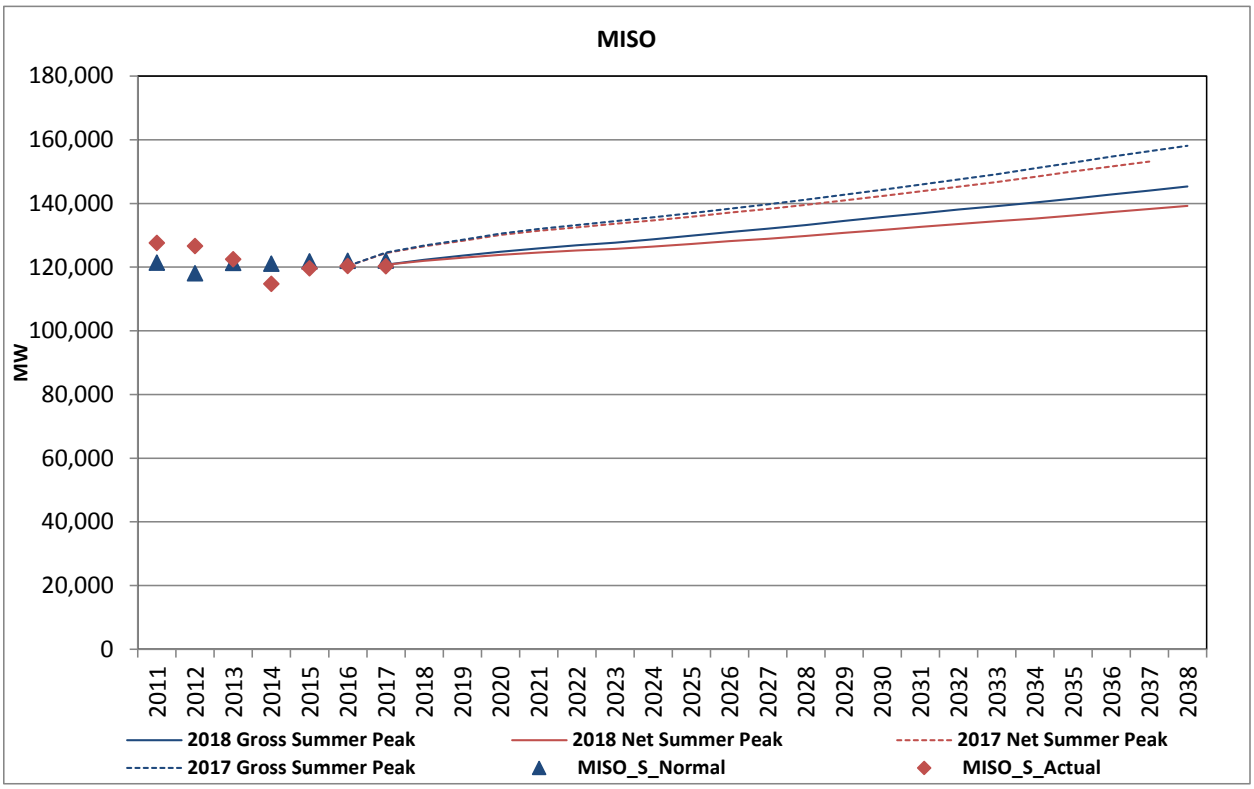
Table 55: MISO Coincident Factors—Winter

LRZ	Winter Coincident Factor								
	Average	2010	2011	2012	2013	2014	2015	2016	2017
1	0.974	0.990	0.994	0.962	1.000	0.994	0.962	0.958	0.932
2	0.971	0.993	0.976	0.963	0.990	0.989	0.944	0.942	0.975
3	0.984	0.996	0.971	1.000	0.979	1.000	0.970	0.995	0.962
4	0.986	1.000	1.000	1.000	0.980	0.992	0.957	0.978	0.980
5	0.990	0.962	1.000	1.000	0.964	1.000	1.000	1.000	0.991
6	0.978	0.983	0.993	0.992	0.928	0.988	0.988	0.961	0.988
7	0.952	0.988	0.958	0.938	0.959	0.944	0.936	0.927	0.965
8	0.965	0.889	0.929	0.995	0.954	0.981	1.000	1.000	0.974
9	0.938	0.832	0.950	0.895	0.887	0.977	0.984	1.000	0.981
10	0.946	0.924	0.892	0.936	0.858	0.998	0.999	0.995	0.964

Table 56: Gross and Net MISO System Coincident Peak Demand (Metered Load in MW)

Year	MISO Summer CP without EE Adjustments	MISO Summer CP with EE Adjustments	MISO Winter CP without EE Adjustments	MISO Winter CP with EE Adjustments
2017	120,779	120,779	99,870	99,870
2018	122,310	121,992	101,124	100,803
2019	123,636	122,992	102,232	101,582
2020	124,793	123,815	103,208	102,220
2021	125,907	124,609	104,131	102,820
2022	126,824	125,202	104,907	103,270
2023	127,689	125,743	105,669	103,704
2024	128,744	126,473	106,567	104,274
2025	129,890	127,301	107,523	104,909
2026	131,016	128,125	108,459	105,540
2027	132,093	128,913	109,353	106,142
2028	133,244	129,776	110,310	106,809
2029	134,482	130,733	111,336	107,552
2030	135,718	131,689	112,361	108,294
2031	136,908	132,630	113,347	109,027
2032	138,057	133,527	114,295	109,721
2033	139,173	134,390	115,217	110,387
2034	140,310	135,277	116,162	111,079
2035	141,537	136,252	117,177	111,838
2036	142,791	137,252	118,217	112,621
2037	144,056	138,261	119,267	113,413
2038	145,317	139,267	120,313	114,201
Compound Annual Growth Rates (%)				
2019-2023	0.81	0.55	0.83	0.52
2019-2028	0.84	0.60	0.85	0.56
2019-2038	0.85	0.66	0.86	0.62

Figure 41: Gross and Net MISO System Summer Coincident Peak Demand (Metered Load in MW)



5.3 MISO SYSTEM HIGH AND LOW FORECASTS

Alternate 90/10 (High/Low) forecasts were developed. Figure 42 shows the MISO system net energy forecasts for the Low, Base and High scenarios and Table 57 provides the growth rates for net energy and seasonal peaks. Appendix E contains more information on the high and low forecasts. Appendix E provides the data tables for these alternate forecasts.

Figure 42: Net MISO System Energy for Alternate Forecasts (Annual Metered Load in GWh)

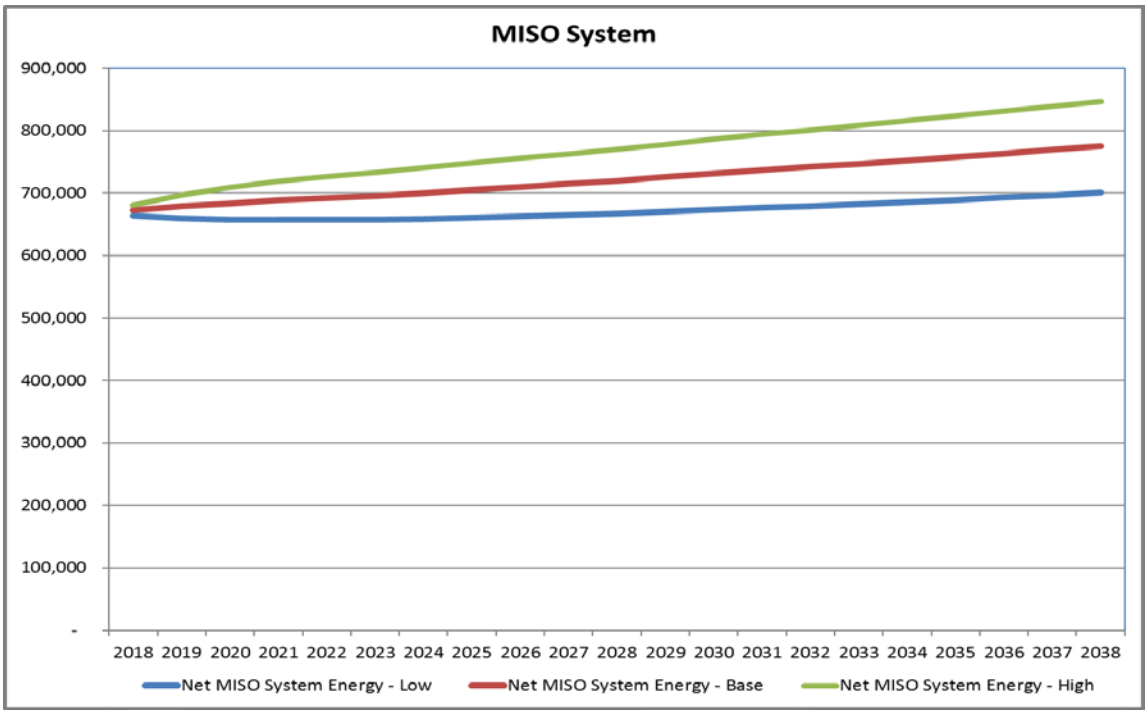


Table 57: Net MISO System Compound Annual Growth Rates for Alternate Forecasts (2019-2038)

	BASE	HIGH	LOW
Energy	0.70	1.03	0.32
Summer Peak	0.66	0.98	0.27
Winter Peak	0.62	0.95	0.24

APPENDIX A State Electric Energy Forecasting Models

SUFG developed econometric models of annual retail electricity sales for each of 15 MISO states using Eviews, a statistical analysis program. The econometric models are based on historical values for a variety of explanatory variables (or drivers). The candidate variables and their data sources are provided in Table 58.

Table 58: Dependent and Explanatory Variables

Variables	Eviews Name	Historical Data Source	Projected Data Source
Dependent variable:			
Electricity sales	ELECTRICITY_SALES	U.S. Energy Information Administration(EIA)	N/A
Explanatory variables:			
Electricity prices	REAL_ELECTRICITY_PRICE	EIA*	SUFG projection based on EIA data
Natural gas prices	REAL_NATURAL_GAS_PRICE	EIA*	SUFG projection based on EIA data
Real personal income	REAL_INCOME	U.S. Bureau of Economic Analysis*	IHS Markit
Population	POPULATION	Census Bureau	IHS Markit
Manufacturing employment	MANUFACTURING_EMP	U.S. Bureau of Labor Statistics(BLS)	IHS Markit
Non-manufacturing employment	NON_MANUFACTURING_EMP	BLS	IHS Markit
Non-farm employment	NON_FARM_EMP	BLS	IHS Markit
Gross state product	REAL_GSP	IHS Markit	IHS Markit
Cooling degree days	CDD	National Oceanic and Atmospheric Administration(NOAA)	NOAA
Heating degree days	HDD	NOAA	NOAA

** Original data was in nominal dollars. SUFG converted it to real 2009 dollars using CPI data obtained from BLS.*

Each state's electricity sales forecast was determined using projections of values for the applicable drivers for that state. Table 59 provides compound annual growth rates for the explanatory variables over the forecast period (2019-2038). Cells with no entry indicate that the corresponding variables are not included in that state's model. Cooling degree days and heating degree days are held constant at their 30-year normal values from NOAA for the projections. The projections provided in Table 59 are from a macroeconomic forecast by IHS Markit, except the electricity price forecast and the natural gas price forecast. Those were developed by SUFG using a similar method adopted in the 2015 forecast, with details being provided in the 2015 report.

Table 59: Explanatory Variable Compound Annual Growth Rates for the 2019-2038 Period (%)

Variables	AR	IL	IN	IA	KY	LA	MI	MN	MS	MO	MT	ND	SD	TX	WI
REAL_ELECTRICITY_PRICE	0.39	0.10	0.09	0.07	-0.15	0.39	0.10	0.05	-0.15	0.06	0.43	0.05	0.05	0.38	0.09
REAL_NATURAL_GAS_PRICE	0.87	0.91	0.88	0.84	0.80	1.19					0.96		0.86	1.04	0.91
REAL_INCOME		1.44		1.80		1.38	1.27		1.63						
POPULATION					0.38			0.46		0.40		0.48	0.69		
REAL_INCOME/POPULATION											1.28				
REAL_GSP	1.65		1.65						1.57					2.70	1.59
NON_MANUFACTURING_EMP															
MANUFACTURING_EMP										-0.14	-0.04				

Table 60 provides the gross (i.e., prior to any EE adjustments) state-level forecasts. The retail sales by state for the year 2017 are not actual observed values since EIA had not published the final release of that year's data. Therefore, the state econometric models were used to "forecast" 2017 values (as well as 2018 values) to provide continuity between the historical data and the forecast period (2019 to 2038).

Table 60: Gross State Energy Forecasts (Annual Retail Sales in GWh)[7]

Year	AR	IL	IN	IA	KY	LA	MI	MN
1990	27,365	111,577	73,982	29,437	61,097	63,826	82,367	47,167
1991	28,440	116,869	77,034	30,781	64,194	64,704	84,519	48,755
1992	28,451	112,521	76,977	30,208	67,068	65,098	83,840	47,412
1993	31,663	117,786	81,931	32,104	68,149	67,756	87,589	49,211
1994	32,619	121,490	83,808	33,039	72,485	70,132	91,160	51,155
1995	34,671	126,231	87,006	34,301	74,548	72,827	94,701	53,959
1996	36,137	125,990	88,901	34,999	77,019	75,269	96,302	54,942
1997	36,858	126,953	89,147	36,148	76,836	75,886	97,391	55,674
1998	39,315	131,697	92,059	37,318	75,850	77,716	100,506	56,744
1999	39,789	132,682	96,735	38,034	79,098	78,267	103,981	57,399
2000	41,611	134,697	97,775	39,088	78,316	80,690	104,772	59,782
2001	41,732	136,034	97,734	39,444	79,975	74,693	102,409	60,687
2002	42,450	138,447	101,429	40,898	87,267	79,261	104,714	62,162
2003	43,108	136,248	100,468	41,207	85,220	77,769	108,877	63,087
2004	43,672	139,254	103,094	40,903	86,521	79,737	106,606	63,340
2005	46,165	144,986	106,549	42,757	89,351	77,389	110,445	66,019
2006	46,636	142,448	105,664	43,337	88,743	77,468	108,018	66,770
2007	47,055	146,055	109,420	45,270	92,404	79,567	109,297	68,231
2008	46,135	144,620	106,981	45,488	93,428	78,726	105,781	68,794
2009	43,173	136,688	99,312	43,641	88,897	78,670	98,121	64,004
2010	48,194	144,761	105,994	45,445	93,569	85,080	103,649	67,800
2011	47,928	142,886	105,818	45,655	89,538	86,369	105,054	68,533
2012	46,860	143,540	105,173	45,709	89,048	84,731	104,818	67,989
2013	46,683	141,805	105,487	46,705	84,764	85,808	103,038	68,644
2014	47,080	141,540	106,943	47,202	78,839	90,628	103,314	68,719
2015	46,465	138,620	104,515	47,147	76,039	91,676	102,480	66,579
2016	46,188	141,050	103,705	48,431	74,554	91,453	104,468	66,546
2017	47,559	140,309	106,764	47,001	77,049	88,492	106,189	68,555
2018	48,106	141,542	108,221	47,447	77,456	89,663	108,029	69,479
2019	48,837	141,878	109,433	48,581	78,586	89,978	108,678	70,168
2020	49,427	142,249	110,457	49,300	79,515	90,570	109,104	71,067
2021	49,957	143,023	111,308	50,330	80,636	90,661	109,949	71,468
2022	50,514	143,829	112,361	50,990	81,638	90,863	110,015	71,802
2023	51,117	144,504	113,543	51,479	82,754	91,481	109,305	72,454
2024	51,695	145,267	114,774	52,103	83,851	91,800	109,485	73,388
2025	52,248	145,844	115,962	52,945	84,811	92,079	110,211	74,124
2026	52,752	146,533	117,300	53,717	85,649	92,284	110,963	74,731
2027	53,230	147,105	118,619	54,413	86,427	92,419	111,714	75,322
2028	53,783	147,773	120,080	55,131	87,182	92,723	112,435	75,949
2029	54,398	148,501	121,620	55,957	87,891	93,100	113,278	76,520
2030	55,001	149,339	123,153	56,765	88,557	93,534	114,180	77,084
2031	55,584	149,995	124,659	57,653	89,174	93,932	114,986	77,537
2032	56,163	150,792	126,185	58,487	89,717	94,366	115,877	77,818
2033	56,765	151,579	127,735	59,212	90,253	94,815	116,775	78,107
2034	57,399	152,332	129,373	59,969	90,808	95,270	117,518	78,476
2035	58,060	153,082	130,982	60,830	91,403	95,760	118,471	78,903
2036	58,761	153,824	132,664	61,697	92,015	96,227	119,376	79,356
2037	59,450	154,662	134,384	62,570	92,605	96,769	120,228	79,782
2038	60,160	155,444	136,109	63,443	93,197	97,252	121,098	80,227
Compound Annual Growth Rates (%)								
2019-2023	1.15	0.46	0.93	1.46	1.30	0.41	0.14	0.80
2019-2028	1.08	0.45	1.04	1.42	1.16	0.33	0.38	0.88
2019-2038	1.10	0.48	1.15	1.41	0.90	0.41	0.57	0.71

[7] The gross forecast is prior to the EE adjustments.

Table 60: Gross State Energy Forecasts (Annual Retail Sales in GWh) – continued

Year	MS	MO	MT	ND	SD	TX	WI
1990	32,127	53,925	13,125	7,014	6,334	237,415	49,198
1991	33,019	56,514	13,407	7,255	6,685	240,352	51,032
1992	33,241	54,411	13,096	7,128	6,494	239,431	50,925
1993	34,749	58,622	12,929	7,432	6,905	250,084	53,156
1994	36,627	59,693	13,184	7,681	7,174	258,180	55,412
1995	37,868	62,259	13,419	7,883	7,414	263,279	57,967
1996	39,622	64,843	13,820	8,314	7,736	278,450	58,744
1997	40,089	65,711	11,917	8,282	7,773	286,704	60,094
1998	42,510	69,010	14,145	8,220	7,824	304,705	62,061
1999	43,980	69,045	13,282	9,112	7,922	301,844	63,547
2000	45,336	72,643	14,580	9,413	8,283	318,263	65,146
2001	44,287	73,213	11,447	9,810	8,627	318,044	65,218
2002	45,452	75,001	12,831	10,219	8,937	320,846	66,999
2003	45,544	74,240	12,825	10,461	9,080	322,686	67,241
2004	46,033	74,054	12,957	10,516	9,214	320,615	67,976
2005	45,901	80,940	13,479	10,840	9,811	334,258	70,336
2006	46,936	82,015	13,815	11,245	10,056	342,724	69,821
2007	48,153	85,533	15,532	11,906	10,603	343,829	71,301
2008	47,721	84,382	15,326	12,416	10,974	347,815	70,122
2009	46,049	79,897	14,354	12,649	11,010	345,351	66,286
2010	49,687	86,085	13,771	12,956	11,356	358,458	68,752
2011	49,338	84,255	13,788	13,737	11,680	376,065	68,612
2012	48,388	82,435	13,863	14,717	11,734	365,104	68,820
2013	48,782	83,407	14,045	16,033	12,210	378,817	69,124
2014	49,409	83,878	14,102	18,240	12,355	389,670	69,495
2015	48,692	81,504	14,207	18,129	12,102	392,337	68,699
2016	49,050	78,618	14,101	18,520	12,130	398,662	69,736
2017	50,496	82,128	14,715	18,284	12,612	399,726	70,895
2018	51,603	82,960	14,996	18,424	12,807	408,214	71,853
2019	52,387	83,716	16,041	18,921	13,146	416,607	72,920
2020	53,254	84,609	16,554	19,488	13,448	423,078	73,677
2021	54,120	85,470	16,834	20,267	13,781	429,153	74,331
2022	55,038	86,192	17,092	20,741	14,015	436,536	75,134
2023	55,960	87,022	17,289	21,117	14,235	444,716	75,831
2024	56,824	87,873	17,439	21,597	14,518	452,369	76,463
2025	57,584	88,847	17,537	22,175	14,851	459,169	77,191
2026	58,297	89,976	17,716	22,605	15,146	466,033	78,018
2027	58,987	91,097	17,833	22,935	15,407	473,126	78,906
2028	59,709	92,022	17,944	23,234	15,664	481,066	79,877
2029	60,472	92,874	18,027	23,535	15,920	489,603	80,951
2030	61,295	93,675	18,194	23,792	16,166	498,163	81,918
2031	62,074	94,400	18,311	24,034	16,404	507,284	82,974
2032	62,836	95,046	18,466	24,207	16,619	516,456	83,936
2033	63,586	95,646	18,682	24,287	16,798	525,519	84,851
2034	64,387	96,258	18,979	24,373	16,976	535,153	85,784
2035	65,237	96,893	19,274	24,500	17,168	544,639	86,712
2036	66,087	97,585	19,560	24,654	17,371	554,564	87,712
2037	66,936	98,330	19,805	24,820	17,582	564,837	88,706
2038	67,780	99,106	20,005	24,966	17,783	575,495	89,694
Compound Annual Growth Rates (%)							
2019-2023	1.66	0.97	1.89	2.78	2.01	1.65	0.98
2019-2028	1.46	1.06	1.25	2.31	1.97	1.61	1.02
2019-2038	1.37	0.89	1.17	1.47	1.60	1.72	1.10

STATE MODELS

The state energy forecasting models and associated modeling statistics follow. The Eviews software package is used for linear regression modeling.

Arkansas

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	7997.335	5232.202	1.528483	0.1472	
@MOVAV(REAL_ELECTRICITY_PRICE,4)	-974.2413	408.3832	-2.385606	0.0307	-0.1537
REAL_NATURAL_GAS_PRICE	284.4885	92.17246	3.086481	0.0075	0.0397
REAL_GSP	0.278789	0.018192	15.32509	0.0000	0.6560
CDD	4.495245	0.613019	7.332961	0.0000	0.1885
HDD	1.708262	0.442772	3.858106	0.0015	0.1342

R-squared	0.981704	Mean dependent var	43963.51
Adjusted R-squared	0.975605	S.D. dependent var	3616.722
S.E. of regression	564.8931	Durbin-Watson stat	1.933566
F-statistic	160.9675		
Prob(F-statistic)	0.000000		

Illinois

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	79267.68	14669.54	5.403556	0.0001	
REAL_ELECTRICITY_PRICE	-1779.53	733.1073	-2.42738	0.0283	-0.1058
REAL_NATURAL_GAS_PRICE(-1)	1047.483	252.692	4.145297	0.0009	0.0477
REAL INCOME	0.0000633	0.0000164	3.852153	0.0016	0.2661
CDD	13.73561	3.059202	4.489932	0.0004	0.0981
HDD	3.192515	1.236322	2.582268	0.0208	0.1354

R-squared	0.901057	Mean dependent var	138619.1
Adjusted R-squared	0.868076	S.D. dependent var	5752.518
S.E. of regression	2089.391	Durbin-Watson stat	1.722164
F-statistic	27.32052		
Prob(F-statistic)	0.000000		

STATE MODELS

Indiana

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1994 2016
Included observations: 23

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	34040.67	6275.603	5.424286	0.0000	
@MOVAV(REAL_ELECTRICITY_PRICE,3)	-2618.308	621.0073	-4.216227	0.0006	-0.2069
@MOVAV(REAL_NATURAL_GAS_PRICE,2)	455.9379	203.4126	2.241444	0.0386	0.0258
REAL_GSP	0.231176	0.009514	24.29745	0.0000	0.6701
CDD	7.249942	1.442948	5.024397	0.0001	0.0777
HDD	2.415416	0.668004	3.615869	0.0021	0.1322

R-squared	0.982869	Mean dependent var	100161.6
Adjusted R-squared	0.977831	S.D. dependent var	7351.366
S.E. of regression	1094.564	Durbin-Watson stat	1.314745
F-statistic	195.0753		
Prob(F-statistic)	0.000000		

Iowa

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	16870.64	3790.158	4.451172	0.0005	
REAL_ELECTRICITY_PRICE(-2)	-1565.046	329.4068	-4.751104	0.0003	-0.2387
REAL_NATURAL_GAS_PRICE(-2)	229.7269	61.64316	3.726722	0.0020	0.0356
REAL INCOME	0.000272	1.13E-05	24.03273	0.0000	0.7239
CDD	2.808754	0.707035	3.972579	0.0012	0.0622
HDD	0.479795	0.192745	2.489266	0.025	0.0737

R-squared	0.992251	Mean dependent var	42610.76
Adjusted R-squared	0.989668	S.D. dependent var	3969.136
S.E. of regression	403.4541	Durbin-Watson stat	1.871969
F-statistic	384.1362		
Prob(F-statistic)	0.000000		

STATE MODELS

Kentucky

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-90813.08	17071.65	-5.319525	0.0001	
@MOVAV(REAL_ELECTRICITY_PRICE,3)	-3318.914	1255.891	-2.642678	0.0185	-0.2837
@MOVAV(REAL_NATURAL_GAS_PRICE,3)	734.9339	268.2416	2.739821	0.0152	0.0522
POPULATION	0.039214	0.00551	7.116283	0.0000	2.0024
CDD	4.367273	1.849944	2.360759	0.0322	0.0681
HDD	4.54976	1.125907	4.040974	0.0011	0.2324

R-squared	0.951876	Mean dependent var	86166.14
Adjusted R-squared	0.935835	S.D. dependent var	5847.143
S.E. of regression	1481.128	Durbin-Watson stat	1.850402
F-statistic	59.33933		
Prob(F-statistic)	0.000000		

Louisiana

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	48245.37	8036.353	6.003391	0.0000	
REAL_ELECTRICITY_PRICE(-2)	-2194.594	538.3219	-4.076732	0.0010	-0.1759
REAL_NATURAL_GAS_PRICE	-655.6612	178.5169	-3.672823	0.0023	-0.0222
REAL INCOME	0.000169	0.0000225	7.504014	0.0000	0.3271
CDD	6.745231	2.033971	3.316287	0.0047	0.2515
HDD	5.341063	1.810201	2.950536	0.0099	0.0970

R-squared	0.932414	Mean dependent var	81278.67
Adjusted R-squared	0.909886	S.D. dependent var	5325.338
S.E. of regression	1598.615	Durbin-Watson stat	1.834548
F-statistic	41.38809		
Prob(F-statistic)	0.000000		

Michigan

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1993 2016
Included observations: 24

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	67219.66	10491.11	6.407296	0.0000	
REAL_ELECTRICITY_PRICE(-3)	-3324.069	320.5015	-10.37146	0.0000	-0.3285
REAL INCOME	0.000132	0.0000158	8.332633	0.0000	0.4962
CDD	8.232416	2.163918	3.804404	0.0012	0.0656
HDD	2.132905	0.873304	2.442339	0.0245	0.1301

R-squared	0.947101	Mean dependent var	102395.4
Adjusted R-squared	0.935965	S.D. dependent var	5662.765
S.E. of regression	1432.974	Durbin-Watson stat	1.57512
F-statistic	85.04424		
Prob(F-statistic)	0		

Minnesota

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-34578.4	7716.765	-4.480945	0.0004	
REAL_ELECTRICITY_PRICE(-1)	-2761.373	723.8497	-3.814843	0.0015	-0.3579
POPULATION	0.02001	0.001837	10.89174	0.0000	1.6598
CDD	8.319551	2.554485	3.256841	0.0049	0.0896
HDD	1.414425	0.495638	2.853745	0.0115	0.1732

R-squared	0.941528	Mean dependent var	63926.05
Adjusted R-squared	0.92691	S.D. dependent var	4697.838
S.E. of regression	1270.067	Durbin-Watson stat	1.647825
F-statistic	64.40897		
Prob(F-statistic)	0.000000		

STATE MODELS

Mississippi

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	12032.65	3440.877	3.496973	0.0032	
@MOVAV(REAL_ELECTRICITY_PRICE,3)	-1963.547	378.8537	-5.182863	0.0001	-0.3346
REAL_INCOME(-1)	0.000193	6.18E-05	3.118957	0.0070	0.3701
REAL_GSP	0.23046	0.083751	2.751723	0.0148	0.4477
CDD	3.731709	0.729032	5.11872	0.0001	0.1846
HDD	2.137433	0.562375	3.800728	0.0017	0.1124

R-squared	0.969146	Mean dependent var	46236.11
Adjusted R-squared	0.958862	S.D. dependent var	2910.506
S.E. of regression	590.3248	Durbin-Watson stat	1.985191
F-statistic	94.23326		
Prob(F-statistic)	0.000000		

Missouri

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-138083.9	38891.12	-3.550525	0.0029	
@MOVAV(REAL_ELECTRICITY_PRICE,5)	-3995.924	435.2837	-9.180046	0.0000	-0.4249
POPULATION	0.033884	0.005302	6.390526	0.0000	2.6261
MANUFACTURING_EMP	0.062171	0.023889	2.602543	0.0200	0.2078
CDD	7.942293	1.457584	5.448944	0.0001	0.1540
HDD	3.991143	0.749111	5.327837	0.0001	0.2376

R-squared	0.978589	Mean dependent var	77652.88
Adjusted R-squared	0.971452	S.D. dependent var	6705.843
S.E. of regression	1133.022	Durbin-Watson stat	1.788196
F-statistic	137.1168		
Prob(F-statistic)	0.000000		

Montana

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-3986.463	3346.745	-1.191146	0.2534	
REAL_ELECTRICITY_PRICE	-1727.114	208.8767	-8.268579	0.0000	-0.9679
@MOVAV(REAL_NATURAL_GAS_PRICE,5)	375.663	60.92514	6.165976	0.0000	0.1884
REAL_INCOME/POPULATION	414.8955	40.5622	10.22863	0.0000	1.1296
MANUFACTURING_EMP	0.314856	0.063094	4.990295	0.0002	0.4358
CDD	1.918328	0.652252	2.941085	0.0107	0.0649
HDD	0.913984	0.224622	4.068984	0.0011	0.4748

R-squared	0.937697	Mean dependent var	13723.19
Adjusted R-squared	0.910995	S.D. dependent var	967.1413
S.E. of regression	288.5336	Durbin-Watson stat	2.251128
F-statistic	35.11788		
Prob(F-statistic)	0.000000		

North Dakota

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1998 2016
Included observations: 19

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-34911.8	2650.76	-13.17049	0.0000	
REAL_ELECTRICITY_PRICE(-2)	-1618.518	247.9155	-6.528505	0.0000	-0.6660
POPULATION	0.083248	0.002592	32.11803	0.0000	3.4070
HDD	0.314905	0.164743	1.911488	0.0752	0.2111

R-squared	0.98647	Mean dependent var	12586.33
Adjusted R-squared	0.983764	S.D. dependent var	3200.938
S.E. of regression	407.864	Durbin-Watson stat	1.9333
F-statistic	364.5515		
Prob(F-statistic)	0.000000		

South Dakota

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1995 2016
Included observations: 22

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	-18186.06	1188.603	-15.30037	0.0000	
REAL_ELECTRICITY_PRICE(-2)	-572.4136	61.44786	-9.315436	0.0000	-0.3870
REAL_NATURAL_GAS_PRICE(-1)	43.5981	19.76565	2.20575	0.0424	0.0192
POPULATION	0.037678	0.000742	50.79983	0.0000	2.6884
CDD	0.624101	0.148579	4.200459	0.0007	0.0451
HDD	0.285388	0.042487	6.717077	0.0000	0.2110

R-squared	0.997548	Mean dependent var	9946.814
Adjusted R-squared	0.996782	S.D. dependent var	1726.755
S.E. of regression	97.95609	Durbin-Watson stat	1.861101
F-statistic	1301.912		
Prob(F-statistic)	0.000000		

Texas

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	93337.17	19510.45	4.783957	0.0002	
REAL_ELECTRICITY_PRICE(-2)	-4078.944	1838.177	-2.219015	0.0423	-0.0829
REAL_NATURAL_GAS_PRICE(-2)	2486.691	980.431	2.536324	0.0228	0.0318
REAL_GSP	0.146545	0.004998	29.31819	0.0000	0.5510
CDD	25.13267	5.448175	4.613043	0.0003	0.2266
HDD	15.80796	5.301451	2.981817	0.0093	0.0852

R-squared	0.988974	Mean dependent var	340249.8
Adjusted R-squared	0.985299	S.D. dependent var	34566.54
S.E. of regression	4191.165	Durbin-Watson stat	2.101659
F-statistic	269.0836		
Prob(F-statistic)	0.000000		

Wisconsin

Dependent Variable: ELECTRICITY_SALES
Method: Least Squares
Sample: 1996 2016
Included observations: 21

Variable	Coefficient	Std. Error	t-Statistic	Prob.	Elasticity at 2016 (weather at means)
C	24875.42	2683.658	9.269223	0.0000	
@MOVAV(REAL_ELECTRICITY_PRICE,5)	-986.0362	252.5938	-3.903644	0.0014	-0.1361
REAL_NATURAL_GAS_PRICE	367.7294	76.09553	4.83247	0.0002	0.0300
REAL_GSP	0.164874	0.011086	14.8726	0.0000	0.6458
CDD	4.403688	1.034685	4.256067	0.0007	0.0390
HDD	0.646072	0.301474	2.143042	0.0489	0.0681

R-squared	0.984625	Mean dependent var	67053.89
Adjusted R-squared	0.979501	S.D. dependent var	3447.182
S.E. of regression	493.5537	Durbin-Watson stat	2.069814
F-statistic	192.128		
Prob(F-statistic)	0.000000		

APPENDIX B Allocation Factors

Allocation factors were used to convert annual electricity sales forecasts at the state level to the MISO LRZ level energy forecasts. The shares of electricity sales within the MISO market footprint were calculated from sales of the LBAs within the MISO market footprint. The correspondence between LBAs and LRZs within MISO is displayed in Table 61. EIA Form 861's historical annual electricity sales data from 2009 to 2016 were used to estimate the annual MISO load fraction at the state level.

The MISO market footprint covers all or parts of 17 states and is divided into 10 LRZs.[8] Figure 1 in Chapter 1 displays the MISO market footprint at the LRZ level.

Table 61: MISO Local Balancing Authorities, 2018

LBA	Local Balancing Authority (MISO)	LRZ	LBA	Local Balancing Authority (MISO)	LRZ
DPC	Dairy Land Power Cooperative	1	AMMO	Ameren - Missouri	5
GRE	Great River Energy	1	CWLD	Columbia Water & Light District	5
MDU	Montana-Dakota Utilities	1	BREC	Big Rivers Electric Cooperative	6
MP	Minnesota Power, Inc.	1	CIN	Cinergy	6
NSP	Northern States Power	1	HE	Hoosier Energy	6
OTP	Otter Tail Power Company	1	IPL	Indianapolis Power and Light	6
SMP	Southern Minnesota Municipal Power Association	1	NIPS	Northern Indiana Public Service Company	6
ALTE	Alliant East	2	SIGE	Southern Indiana Gas and Electric	6
MGE	Madison Gas and Electric	2	CONS	Consumers	7
MIUP	Michigan Upper Peninsula	2	DECO	Detroit Edison	7
UPPC	Upper Peninsula Power Company	2	EAI	Entergy Arkansas, Inc.	8
WEC	Wisconsin Electric Power Company	2	CLEC	Central Louisiana Electric Company	9
WPS	Wisconsin Public Service Company	2	EES	Entergy Electric System	9
ALTW	Alliant West	3	LAFA	Lafayette Utilities	9
MEC	MidAmerican Electric Company	3	LAGN	Louisiana Generating Company	9
MPW	Muscatine Power & Water	3	LEPA	Louisiana Energy and Power Authority	9
AMIL	Ameren - Illinois	4	EES	Entergy Electric System	10
CWPLP	City Water Light & Power	4	SME	South Mississippi Electric Power Association	10
SIPC	Southern Illinois Power Cooperative	4			

Source: MAP of MEP Local Resource Zone Boundaries, MISO, March 1, 2018

[8] A very small amount of load in Oklahoma and Tennessee is served by MISO LBAs in LRZ 8. Rather than developing individual state econometric models for those states, it is assumed that these loads grow at the rate of the rest of LRZ 8.

ALLOCATION FACTORS

Table 62 summarizes the historical MISO load fractions at the state level for the period of 2009-2016. The category named "MISO Sales" includes all electricity sales from either MISO utilities or utilities listing a MISO LBA as the local balancing authority. At the request of MISO staff and due to concerns over providing utility-specific information in states that only have a single MISO utility, the annual electricity sales of Indiana and Kentucky are combined (IN+KY). Similarly, North Dakota and Montana have been combined (ND+MT).

Table 62: MISO Load Fraction at State Level (MWh), 2016

State	MISO Sales (Megawatt hours)	Non-MISO Sales (Megawatt hours)	2009	2010	2011	2012	2013	2014	2015	2016
AR	33,226,634	12,961,804	70.03%	70.57%	70.39%	70.52%	70.45%	72.23%	72.30%	71.94%
IA	44,970,219	3,460,974	92.03%	92.92%	93.04%	93.22%	92.92%	93.05%	92.92%	92.85%
IL	48,584,860	92,465,549	33.95%	34.55%	34.80%	33.91%	34.59%	34.84%	34.83%	34.45%
IN+KY	90,712,958	87,545,438	47.37%	47.49%	48.49%	48.78%	49.94%	51.95%	51.86%	50.89%
LA	84,817,847	6,634,812	91.82%	91.77%	91.74%	92.06%	92.20%	92.67%	92.66%	92.75%
MI	100,406,003	4,061,810	95.28%	96.01%	96.16%	96.21%	96.10%	96.08%	96.09%	96.11%
MN	65,694,151	852,341	98.66%	98.73%	98.73%	98.84%	98.75%	98.77%	98.76%	98.72%
MO	36,938,198	41,679,858	48.83%	49.55%	49.35%	50.22%	49.38%	49.06%	48.98%	46.98%
MS	21,932,636	27,117,528	45.58%	45.89%	45.24%	44.78%	44.73%	44.56%	45.06%	44.71%
ND+MT	11,248,296	21,372,493	36.03%	37.35%	37.90%	36.76%	37.46%	36.30%	35.14%	34.48%
SD	3,135,799	8,993,731	26.48%	26.87%	26.07%	26.02%	25.32%	25.26%	25.57%	25.85%
TX	21,733,482	376,928,327	5.53%	5.66%	5.46%	5.99%	5.74%	5.60%	5.47%	5.45%
WI	69,736,338	0	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

Source: Electric power sales, revenue, and energy efficiency Form 861 detailed data files, U.S. Energy Information Administration, calculated by SUFG.

Table 63 shows the average percentage of annual electricity sales at the state level that was located in each MISO LRZ. The last row named "Non-MISO" lists the average percentage of electricity sales from non-MISO utilities at the state level.

Table 63: MISO Load Fraction at LRZ Level (Average Percentage of State-Level Electricity Sales from 2009 to 2016)

LRZ	AR	IA	IL	IN+KY	LA	MI	MN	MO	MS	ND+ MT	SD	TX	WI
1		1.8%	0.000 2%			0.1%	97.0%			36.4%	24.1%		16.8%
2						4.9%							83.2%
3		91.1%	1.4%				1.8%				1.8%		
4			33.1%										
5								48.9%					
6				49.6%									
7						91.0%							
8	71.1%							0.0%				0.0%	
9					92.2%							5.6%	
10									45.1%				
Non-MISO	28.9%	7.1%	65.5%	50.4%	7.8%	4.0%	1.3%	51.0%	54.9%	63.6%	74.1%	94.4%	0.0%

Source: Electric power sales, revenue, and energy efficiency Form 861 detailed data files, U.S. Energy Information Administration, calculated by SUFG.

ALLOCATION FACTORS

Table 64 summarizes the percentage of MISO electricity sales in each state for the period of 2009-2016 and the eight-year average by LRZ. For most states, the percentage of electricity sales from MISO utilities was quite stable during this period.

Table 64: State Level MISO Load Fraction by MISO LRZs

MISO LRZ	State	State Level MISO Load Fraction								
		Average	2009	2010	2011	2012	2013	2014	2015	2016
1	IA	1.79%	1.78%	1.77%	1.76%	1.73%	1.78%	1.83%	1.84%	1.81%
	IL	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%	0.0002%
	MI	0.14%	0.14%	0.14%	0.14%	0.13%	0.14%	0.14%	0.13%	0.13%
	MN	96.95%	96.60%	96.73%	96.76%	96.93%	96.89%	96.76%	97.20%	97.78%
	ND+MT	36.42%	35.99%	37.35%	37.90%	36.76%	37.46%	36.30%	35.14%	34.48%
	SD	24.12%	24.64%	24.97%	24.28%	24.24%	23.51%	23.51%	23.78%	24.05%
	WI	16.78%	16.84%	16.59%	16.94%	16.23%	17.02%	17.05%	16.90%	16.68%
2	MI	4.89%	4.32%	5.22%	5.28%	4.89%	4.94%	5.14%	4.83%	4.53%
	WI	83.22%	83.16%	83.41%	83.06%	83.77%	82.98%	82.95%	83.10%	83.32%
3	IA	91.08%	90.25%	91.14%	91.28%	91.48%	91.15%	91.22%	91.07%	91.05%
	IL	1.42%	1.40%	1.42%	1.45%	1.42%	1.42%	1.40%	1.41%	1.42%
	MN[9]	1.79%	2.06%	2.00%	1.97%	1.91%	1.86%	2.01%	1.56%	0.94%
	SD	1.81%	1.84%	1.90%	1.79%	1.77%	1.80%	1.75%	1.79%	1.80%
4	IL	33.07%	32.55%	33.12%	33.35%	32.49%	33.17%	33.44%	33.42%	33.03%
5	MO	48.94%	48.56%	49.41%	49.22%	50.08%	49.26%	49.04%	48.96%	46.96%
6	IN+KY	49.57%	47.35%	47.49%	48.49%	48.60%	49.94%	51.95%	51.86%	50.89%
7	MI	90.98%	90.82%	90.65%	90.75%	91.19%	91.02%	90.80%	91.13%	91.45%
8	AR	71.05%	70.03%	70.57%	70.39%	70.52%	70.45%	72.23%	72.30%	71.94%
	MO	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
	TX	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
9	LA	92.21%	91.82%	91.77%	91.74%	92.06%	92.20%	92.67%	92.66%	92.75%
	TX	5.61%	5.52%	5.65%	5.46%	5.98%	5.73%	5.59%	5.47%	5.45%
10	MS	45.07%	45.58%	45.89%	45.24%	44.78%	44.73%	44.56%	45.06%	44.71%

Source: Electric power sales, revenue, and energy efficiency Form 861 detailed data files, U.S. Energy Information Administration, calculated by SUFG.

In determining the future allocation factors, a number of elements were considered. These include the stability of the historical market shares, any distinct upward or downward trend in the historical market shares, and information regarding expected growth for sub-state areas where those areas are particularly indicative of either the MISO or the non-MISO portion of the state. For example, most of the MISO portion of Missouri is in or near the St. Louis metropolitan area. Since the economic drivers for the St. Louis area grow slower than the entire state of Missouri, the share of electricity sales in the MISO portion is reduced over time. A similar analysis was performed for Illinois using the Chicago metropolitan area, but did not indicate that an adjustment is

[9] Customers of Interstate Power and Light located in Minnesota were transferred to rural electric cooperatives in 2016. Some of the cooperatives are in LRZ 1 while Interstate Power and Light is in LRZ 3. Thus, some loads switched from LRZ 3 to LRZ 1 at that time. Thus, the percentage of Minnesota electricity sales in LRZ 3 dropped from 1.56% to 0.94%, and the share in LRZ 1 increased.

warranted. Table 65 provides the allocation factors for each LRZ. The allocation factors were then applied to the state load forecasts to obtain LRZ-level forecasts of annual calendar-year energy sales. These were then converted to metered load forecasts.

Table 65: Allocation Factors to Convert State Sales to LRZ Sales

MISO LRZ	State	Allocation Factor	
		Basis	Forecasting Period
1	IA	Historical average (2009-2016)	Constant at 1.79%
	IL	Historical average (2009-2016)	Constant at 0.0002%
	MI	Historical average (2009-2016)	Constant at 0.14%
	MN	Historical average (2009-2016)	Constant at 96.95%
	ND+MT	Historical average (2009-2016)	Constant at 36.42%
	SD	Historical average (2009-2016)	Constant at 24.12%
	WI	Historical average (2009-2016)	Constant at 16.78%
2	MI	Historical average (2009-2016)	Constant at 4.89%
	WI	Historical average (2009-2016)	Constant at 83.22%
3	IA	Historical average (2009-2016)	Constant at 91.08%
	IL	Historical average (2009-2016)	Constant at 1.42%
	MN	2016 value	Constant at 0.94%[10]
	SD	Historical average (2009-2016)	Constant at 1.81%
4	IL	Historical average (2009-2016)	Constant at 33.07%
5	MO	St. Louis vs. state growth Decrease over time	Reduced from 48.46% in 2017 to 42.53% in 2038[11]
6	IN+KY	Historical average (2014-2016)	Constant at 51.56%[12]
7	MI	Historical average (2009-2016)	Constant at 90.98%
8	AR	Historical average (2009-2016)	Constant at 71.05%
	MO	Historical average (2009-2016)	Constant at 0.02%
	TX	Historical average (2009-2016)	Constant at 0.0059%
9	LA	Historical average (2009-2016)	Constant at 92.21%
	TX	Historical average (2009-2016)	Constant at 5.61%
10	MS	Historical average (2009-2016)	Constant at 45.07%

[10] Minnesota's allocation factor in LRZ3 for 2016 dropped from previous years because of the transfer of Interstate Power and Light customers in 2016.

[11] Based on the projections of the values for the model drivers for the state of Missouri and for the St. Louis metropolitan statistical area from IHS Markit, the non-MISO region is projected to grow faster than the MISO region. Therefore, the allocation factor for LRZ5 is reduced from 48.46% in 2017 to 42.53% in 2038.

[12] Because the 2014, 2015 and 2016 values reflect the MISO shares in LRZ 6 after the complete shutdown of the Paducah Gaseous Diffusion Plant in Kentucky, the future allocation factor is held constant at the average of 2014, 2015 and 2016 values (51.56%).

APPENDIX C Peak Demand Models

Peak load conversion factors were used to translate annual metered load at the MISO LRZ level to summer and winter non-coincident peak demands. These conversion factors are based on normal weather conditions at the time of peak demand and are determined from historical relationships between hourly load factors, summer/winter peak levels for the year, and weather conditions at the time of the peak demand.

The process involves three steps: (1) determine the relationship between the peak demand (relative to the average demand level for the year) and temperature using historical data, (2) estimate the "normal" weather conditions when peak demand occurs, and (3) calculate the peak hourly demand given the peak load factor under normal weather conditions.

The zonal hourly load data were obtained from MISO and contains eight years' of hourly load observations of LRZ-level loads from January 1, 2010 to December 31, 2017. Actual hourly weather data from 1997 to 2017 was obtained from the Midwest Regional Climate Center. For each LRZ, one weather station was selected to be centrally located within the load center of a particular LRZ. Table 66 lists the selected weather stations for each LRZ.

Table 66: Selected Weather Stations for LRZs, Midwest Regional Climate Center

LRZ	City	Station WBAN ID	Station Call Sign
1	Minneapolis-St. Paul, MN	14922	KMSP
2	Milwaukee, WI	14839	KMKE
3	Des Moines, IA	14933	KDSM
4	Springfield, IL	93822	KSPI
5	St. Louis, MO	13994	KSTL
6	Indianapolis, IN	93819	KIND
7	Lansing, MI	14836	KLAN
8	Little Rock, AR	13963	KLIT
9	Lake Charles, LA	03937	KLCH
10	Jackson, MS	03940	KJAN

Multiple linear regression (MLR) analyses were employed to estimate the relationship of peak load factor and temperature quantitatively. In this study, several MLR models were developed such as classical models with seasonal dummy variables, autoregressive models and models with moving average of hourly temperatures, etc. There are an extremely large number of possible models for peak load factor forecasting using various techniques and methodologies. Multiple statistics such as R squared, Akaike information criterion (AIC) and mean absolute percentage error (MAPE) are used to measure the advantages of one model over another.

MISO provided eight years zonal hourly load records from 2010 to 2017. Preliminary data screening and sample selection are necessary for peak load factor modeling. More than half of those records either are insensitive to the changes of temperature or occur at the time when peak demand is unlikely to occur, namely weekend and holiday loads, spring and fall loads, and hourly loads between 9 pm and 6 am. Thus, SUFG decided to only select those hourly records that are sensitive to temperature changes for regression analysis. For each LRZ, the winter and summer weekday daily peak hourly loads were selected. The loads that occurred in January, February, November and December are categorized as winter loads while the loads occurring from June to September are grouped as summer loads. The loads that occur outside of the summer and winter seasons were removed since

they were not sensitive to changes of hourly temperature. The remaining loads and corresponding temperature information were then used in the regression analysis for each LRZ.

Other than the current hourly temperature, the moving average of past three hours, six hours, twelve hours, twenty four hours, thirty six hours, forty eight hours, sixty hours and seventy-two hours are used as potential weather-related variables. Other than weather related variables, seasonal dummy variables indicating summer and winter peaks are used to adjust the peak effect on load factors. The daily peak load factor is used as the dependent variable for the peak demand model.

The historical average of actual observed peak weather conditions are used as the most likely seasonal peak weather condition. Table 67 presents the historical zonal peak load factors and associated temperatures from 2010 to 2017. "Temp" represents the actual temperature when peak occurred. For summer peaks, the impact of the mild summers on peak loads can be observed in 2013 and 2014 when multiple summer peaks occurred in September. For winter peaks, it is noted that the 2014 zonal load factors are lower than other years due to the Polar Vortex. The recorded hourly temperature when the peak occurred is generally much colder than previous years. Using just these observations would bias the normal peak conditions calculations to be cooler in both summer and winter.

Table 67: Historical Summer and Winter Peak Load Factors and Temperatures, 2010-2017 (Fahrenheit)

LRZ	Year	Summer Peak			Winter Peak		
		Peak Time	Temp	Load Factor	Peak Time	Temp	Load Factor
1	2010	8/9/2010 15:00	93	65%	12/20/2010 18:00	23	76%
	2011	7/20/2011 16:00	95	63%	2/7/2011 19:00	3	78%
	2012	7/2/2012 14:00	98	61%	1/19/2012 8:00	-10	78%
	2013	8/26/2013 14:00	96	63%	12/9/2013 19:00	-2	76%
	2014	7/21/2014 15:00	91	67%	1/22/2014 19:00	-3	75%
	2015	8/14/2015 15:00	91	65%	1/8/2015 19:00	7	73%
	2016	7/20/2016 16:00	89	63%	12/14/2016 19:00	1	75%
	2017	7/6/2017 16:00	93	66%	12/27/2017 18:00	2	74%
2	2010	8/12/2010 15:00	87	60%	12/13/2010 18:00	11	77%
	2011	7/20/2011 16:00	97	56%	2/9/2011 19:00	4	81%
	2012	7/16/2012 15:00	96	56%	1/19/2012 19:00	3	80%
	2013	8/27/2013 15:00	94	59%	12/11/2013 18:00	4	77%
	2014	7/22/2014 16:00	87	63%	1/6/2014 18:00	-12	74%
	2015	8/14/2015 15:00	93	64%	1/7/2015 18:00	-2	75%
	2016	8/10/2016 16:00	86	62%	12/19/2016 18:00	12	78%
	2017	6/12/2017 14:00	92	63%	1/5/2017 18:00	5	78%
3	2010	8/12/2010 15:00	93	61%	12/13/2010 18:00	9	77%
	2011	7/19/2011 17:00	95	59%	2/8/2011 19:00	2	77%
	2012	7/25/2012 16:00	105	58%	1/12/2012 19:00	14	79%
	2013	9/9/2013 16:00	97	60%	12/11/2013 18:00	4	74%
	2014	9/4/2014 16:00	91	65%	1/6/2014 19:00	-4	74%
	2015	7/17/2015 16:00	94	61%	1/7/2015 19:00	-6	74%
	2016	7/21/2016 13:00	95	62%	12/14/2016 19:00	14	77%
	2017	7/19/2017 15:00	96	62%	1/6/2017 8:00	1	78%
4	2010	8/3/2010 16:00	94	59%	12/13/2010 19:00	9	74%
	2011	7/21/2011 16:00	97	56%	2/10/2011 8:00	5	77%
	2012	7/25/2012 16:00	101	55%	1/12/2012 19:00	15	77%
	2013	8/30/2013 15:00	93	60%	12/11/2013 20:00	7	76%
	2014	8/25/2014 15:00	96	60%	1/6/2014 18:00	-10	70%
	2015	7/13/2015 16:00	91	61%	1/7/2015 19:00	-1	69%
	2016	7/21/2016 16:00	93	59%	1/18/2016 18:00	8	73%
	2017	7/21/2017 15:00	95	57%	12/27/2017 18:00	4	74%
5	2010	8/3/2010 16:00	100	57%	1/7/2010 19:00	11	69%

PEAK DEMAND MODELS

LRZ	Year	Summer Peak			Winter Peak		
		Peak Time	Temp	Load Factor	Peak Time	Temp	Load Factor
	2011	8/2/2011 16:00	101	55%	2/10/2011 8:00	13	70%
	2012	7/25/2012 16:00	106	53%	1/12/2012 19:00	17	72%
	2013	8/30/2013 15:00	99	59%	2/1/2013 8:00	13	72%
	2014	8/25/2014 16:00	95	58%	1/6/2014 19:00	-3	64%
	2015	7/13/2015 16:00	97	57%	1/8/2015 8:00	8	64%
	2016	7/21/2016 16:00	98	55%	12/19/2016 8:00	6	64%
	2017	7/21/2017 16:00	102	53%	12/31/2017 19:00	6	66%
6	2010	8/10/2010 16:00	96	65%	12/15/2010 7:00	5	74%
	2011	7/20/2011 14:00	98	63%	2/10/2011 7:00	8	73%
	2012	7/25/2012 16:00	99	63%	1/13/2012 10:00	16	78%
	2013	7/18/2013 15:00	91	65%	12/12/2013 7:00	2	74%
	2014	9/5/2014 15:00	88	68%	1/24/2014 8:00	-4	69%
	2015	7/29/2015 14:00	88	65%	1/7/2015 19:00	-2	67%
	2016	8/11/2016 15:00	90	64%	1/19/2016 7:00	4	70%
	2017	7/21/2017 15:00	86	66%	1/6/2017 8:00	3	72%
7	2010	7/7/2010 15:00	91	56%	12/13/2010 18:00	10	77%
	2011	7/21/2011 14:00	95	52%	12/8/2011 18:00	31	82%
	2012	7/17/2012 15:00	98	51%	1/19/2012 18:00	9	82%
	2013	7/17/2013 14:00	92	53%	12/12/2013 18:00	16	78%
	2014	9/5/2014 15:00	86	59%	1/28/2014 18:00	2	77%
	2015	7/28/2015 15:00	87	57%	1/8/2015 18:00	4	76%
	2016	8/11/2016 15:00	92	55%	12/15/2016 18:00	9	79%
	2017	7/19/2017 16:00	87	58%	12/13/2017 18:00	20	79%
8	2010	8/2/2010 15:00	103	58%	1/8/2010 7:00	13	67%
	2011	8/3/2011 14:00	111	53%	1/13/2011 7:00	17	69%
	2012	7/30/2012 14:00	111	55%	1/12/2012 20:00	30	76%
	2013	7/9/2013 16:00	96	59%	1/15/2013 7:00	26	72%
	2014	8/25/2014 13:00	96	60%	1/24/2014 8:00	17	62%
	2015	7/29/2015 15:00	98	56%	1/8/2015 8:00	15	61%
	2016	7/19/2016 14:00	97	57%	12/20/2016 8:00	19	66%
	2017	7/20/2017 14:00	95	56%	1/6/2017 10:00	21	67%
9	2010	8/2/2010 16:00	95	63%	1/11/2010 8:00	33	67%
	2011	8/31/2011 16:00	94	63%	1/13/2011 8:00	31	69%
	2012	6/26/2012 16:00	96	62%	1/13/2012 8:00	41	78%
	2013	8/7/2013 16:00	91	62%	12/16/2013 7:00	34	75%
	2014	8/22/2014 16:00	90	66%	1/7/2014 7:00	22	65%
	2015	8/10/2015 15:00	99	60%	1/8/2015 7:00	25	68%
	2016	8/2/2016 15:00	92	64%	12/19/2016 8:00	32	75%
	2017	8/18/2017 16:00	91	64%	1/7/2017 9:00	28	71%
10	2010	8/2/2010 14:00	104	56%	1/11/2010 8:00	27	66%
	2011	8/3/2011 14:00	87	52%	1/13/2011 8:00	27	66%
	2012	7/30/2012 16:00	90	52%	1/13/2012 8:00	35	72%
	2013	8/8/2013 16:00	96	55%	1/22/2013 8:00	38	71%
	2014	8/6/2014 16:00	94	58%	1/7/2014 8:00	18	59%
	2015	8/10/2015 15:00	86	54%	1/8/2015 7:00	15	61%
	2016	8/2/2016 15:00	96	55%	12/19/2016 9:00	29	71%
	2017	7/20/2017 16:00	96	54%	1/8/2017 9:00	26	64%

Table 68 summarizes the projected seasonal peak load factors. The column "Temp" represents the hourly temperature when peak occurs. The "MA" represents "moving average". The number after "MA" indicates the number of lags involved in calculation. For example, the column "MA_3" represents the moving average of the past two hourly temperatures and the current temperature. The "MA_72" indicates the average hourly temperature of past three days. It is worth noting that "MA_3" is either higher or the same as the peak hour temperature for most of LRZs in summer. This indicates that summer peaks tend to occur when the temperatures of the two hours previous to the peak hour are at least as high as the temperature during the peak hour. For winter peaks, the peak usually occurs when the temperature of the past two hours is colder than or

as cold as the peak hour temperature. The regression analysis also shows the coldest daily hourly temperature is not statistically significant for determining the daily peak load factor while the average temperature of past 3 hours plays a more significant role in determining the level of the daily peak hourly load.

Table 68: Seasonal Peak Load Factor under Normalized Peak Weather Condition (Fahrenheit)

Summer Peak Load Factor under Normalized Peak Weather Condition											
LRZ	LF	PA ratio*	TEMP	MA_3	MA_6	MA_12	MA_24	MA_36	MA_48	MA_60	MA_72
LRZ1	0.6388	156.5%	93.3	93.3	91.8	85.8	84.0	83.7	82.8	82.2	81.2
LRZ2	0.6027	165.9%	91.5	91.6	90.8	85.5	81.7	81.4	80.1	79.9	78.4
LRZ3	0.6024	166.0%	95.8	96.4	95.5	89.8	86.3	85.5	83.7	83.6	82.8
LRZ4	0.5829	171.6%	95.0	95.4	94.7	89.4	85.5	85.4	83.7	84.0	83.0
LRZ5	0.5605	178.4%	99.8	100.2	99.5	94.0	90.6	90.5	88.9	89.1	88.0
LRZ6	0.6585	151.9%	92.0	92.6	91.0	85.1	83.5	83.4	82.8	82.5	81.7
LRZ7	0.5605	178.4%	91.0	90.8	89.5	83.5	81.6	80.9	79.7	79.4	78.6
LRZ8	0.5579	179.2%	100.9	100.7	98.9	91.4	88.8	88.7	87.8	88.0	87.1
LRZ9	0.6284	159.1%	93.5	94.9	94.9	90.2	86.2	87.4	86.2	86.6	85.7
LRZ10	0.5471	182.8%	93.6	95.4	95.7	91.5	86.9	87.9	85.6	86.0	84.9
Winter Peak Load Factor under Normalized Peak Weather Condition											
LRZ	LF	P/A ratio*	TEMP	MA_3	MA_6	MA_12	MA_24	MA_36	MA_48	MA_60	MA_72
LRZ1	0.7540	132.6%	2.6	3.0	4.6	5.1	6.6	6.3	5.6	6.2	7.1
LRZ2	0.7823	127.8%	3.1	4.0	5.4	4.7	5.3	7.9	9.8	12.5	14.5
LRZ3	0.7606	131.5%	4.3	4.8	5.9	5.7	6.1	8.6	10.4	12.5	14.3
LRZ4	0.7330	136.4%	4.6	4.9	6.1	6.5	8.0	11.0	13.1	15.7	17.1
LRZ5	0.6684	149.6%	8.9	8.2	8.4	8.7	11.9	15.1	17.8	20.9	22.2
LRZ6	0.7300	137.0%	4.0	3.7	4.1	5.9	9.6	11.0	13.1	14.5	16.7
LRZ7	0.7878	126.9%	12.6	13.4	14.3	13.5	12.8	14.5	16.0	17.5	18.2
LRZ8	0.6699	149.3%	19.8	19.1	19.3	21.1	25.7	27.5	29.8	30.3	32.8
LRZ9	0.7164	139.6%	30.8	28.3	27.9	29.9	36.0	37.4	41.8	43.0	44.1
LRZ10	0.6384	156.6%	26.9	23.7	22.9	23.9	28.9	30.1	34.3	35.4	37.1

**: PA ratio: It is the ratio of peak hourly demand to annual average hourly load. It is a reciprocal of the peak load factor.*

The reciprocals of the peak load factors are the peak demand conversion factors in Table 69. For comparison purpose, the conversion factors in the 2014, 2015, 2016 and 2017 forecasts are also included in the table. The study period of each version is listed in parentheses. In general, this year's summer and winter peak conversion factors are similar to the 2016 and 2017 versions. The similar peak weather conditions between 2016 and 2015 result in minor changes in the conversion factors. Additionally, adding one more year's hourly load records enhances the stability of the peak model.

Multiplying the average hourly load for a given year of the forecast by the conversion factor would yield the peak hourly demand. An example of the calculation follows:

Suppose the forecast annual energy for a given year in LRZ 1 is 100 million MWh. The average hourly load is found by dividing the annual energy by the number of hours in the year.

$$\frac{100{,}000{,}000\ MWh}{8{,}760\ hr} = 11{,}416\ MW$$

The summer and winter peak demands are found by multiplying the average hourly load by the appropriate conversion factor, taking the current version for LRZ 1 as an example.

$$11{,}416\ MW * 1.565 = 17{,}866\ MW\ (summer)$$

$$11{,}416\ MW * 1.326 = 15{,}138\ MW\ (winter)$$

Table 69: Peak Demand Conversion Factors

LRZ	2018 Forecast (2010-2017)		2017 Update (2010-2016)		2016 Forecast (2010-2015)		2015 Forecast (2010-2014)		2014 Forecast (2010-2013)	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1	1.565	1.326	1.580	1.314	1.567	1.309	1.541	1.329	1.568	1.282
2	1.659	1.278	1.643	1.290	1.639	1.293	1.695	1.336	1.672	1.267
3	1.660	1.315	1.630	1.318	1.639	1.325	1.635	1.323	1.638	1.275
4	1.716	1.364	1.679	1.353	1.678	1.355	1.707	1.348	1.717	1.303
5	1.784	1.496	1.755	1.491	1.743	1.466	1.741	1.451	1.749	1.405
6	1.519	1.370	1.532	1.385	1.527	1.378	1.508	1.372	1.542	1.340
7	1.784	1.269	1.830	1.266	1.782	1.272	1.792	1.286	1.826	1.245
8	1.792	1.493	1.744	1.470	1.755	1.461	1.726	1.448	1.739	1.412
9	1.591	1.396	1.574	1.398	1.578	1.403	1.536	1.388	1.634	1.363
10	1.828	1.566	1.827	1.546	1.827	1.569	1.831	1.489		

Table 70 lists the model specifications of summer and winter peak load factors. The followings are variable names and definitions:

- SP: binary variable, the value is 1 for summer peak load factor, otherwise it is 0;
- WP: binary variable, the value is 1 for winter peak load factor, otherwise it is 0;
- Temp: hourly temperature observed;
- MAVGTN: Moving average temperature of the previous N-1 hours and the hour when the daily peak occurred; N ranges from 3 to 72;
- Daily Peak Load Factor: dependent variable, the ratio of annual average hourly load over daily peak load.

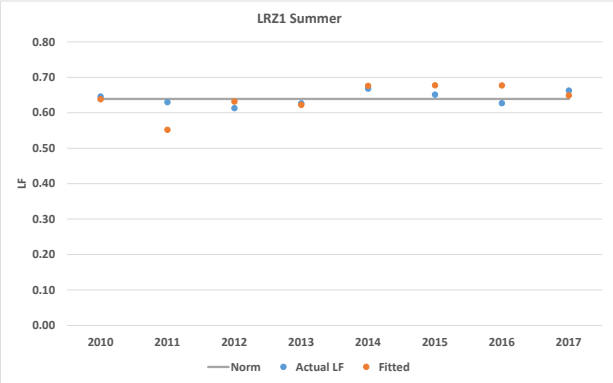
Table 70: Regression Models

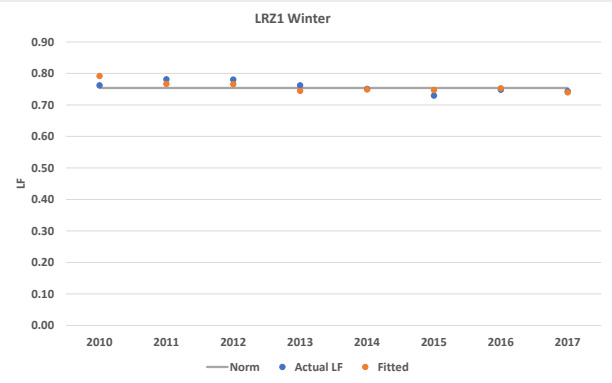
LRZ	Model Specification (Summer Peak Load Factors)
1	$C + Temp + Temp^2 + Temp^3 + MAVGT12^3 + MAVGT24^2 + MAVGT72^2 + SP$
2	$C + MAVGT6 + MAVGT6^2 + MAVGT6^3 + MAVGT12 + MAVGT12^2 + MAVGT12^3 + MAVGT60^3 + SP$
3	$C + MAVGT3 + MAVGT3^2 + MAVGT3^3 + MAVGT12 + MAVGT12^2 + MAVGT12^3 + MAVGT24^2 + MAVGT36^3 + MAVGT48 + MAVGT72^2 + SP$
4	$C + MAVGT3 + MAVGT3^2 + MAVGT3^3 + MAVGT6 + MAVGT6^2 + MAVGT6^3 + MAVGT12 + MAVGT24 + MAVGT48^2 + MAVGT48^3 + MAVGT72 + MAVGT72^2 + MAVGT72^3 + SP$
5	$C + MAVGT3^3 + MAVGT12 + MAVGT12^2 + MAVGT36 + MAVGT72 + MAVGT72^3 + +MAVGT48 + SP$
6	$C + Temp + MAVGT3^2 + MAVGT12 + MAVGT24 + MAVGT48 + MAVGT48^2$
7	$C + Temp + Temp^2 + Temp^3 + MAVGT3 + MAVGT3^2 + MAVGT36 + MAVGT72$
8	$C + Temp + Temp^2 + MAVGT12 + MAVGT12^2 + MAVGT72 + MAVGT72^3 + SP$
9	$C + MAVGT6^3 + MAVGT12 + MAVGT12^2 + MAVGT12^3 + MAVGT48 + MAVGT48^2 + MAVGT48^3 + SP$
10	$C + MAVGT12^2 + MAVGT24 + MAVGT24^2 + MAVGT72$
LRZ	**Model Specification (Winter Peak Load Factors)**
1	$C + Temp + Temp^2 + Temp^3 + MAVGT6 + MAVGT6^3 + MAVGT24 + MAVGT24^3 + MAVGT48^3 + WP$
2	$C + MAVGT3 + MAVGT24 + MAVGT6^2 + MAVGT6^3 + MAVGT72^3 + WP$
3	$C + Temp + Temp^2 + Temp^3 + MAVGT6 + MAVGT6^3 + MAVGT24 + WP$
4	$C + Temp^2 + Temp^3 + MAVGT24 + MAVGT60 + WP$
5	$C + Temp + Temp^2 + Temp^3 + MAVGT6^3 + MAVGT24 + MVAGT48 + WP$
6	$C + Temp + Temp^2 + Temp^3 + MAVGT12 + MAVGT12^3 + MAVGT24 + MAVGT24^2 + MAVGT48^2$
7	$C + Temp + Temp^3 + MAVGT3 + MAVGT3^2 + MAVGT3^3 + MAVGT72 + WP$
8	$C + Temp + Temp^2 + Temp^3 + MAVGT3 + MAVGT24 + MAVGT72 + WP$
9	$C + Temp + Temp^2 + MAVGT3 + MAVGT3^2 + MAVGT3^3 + MAVGT24 + MAVGT60^3 + MAVGT72$
10	$C + Temp^2 + Temp^3 + MAVGT6^2 + MAVGT24 + MAVGT24^2 + MAVGT24^3 + MAVGT72$

The following charts show the comparison of historical peak load factors, fitted peak load factors and normalized peak load factors. The blue dots represent actual peak load factors, the orange dots indicate the fitted peak load factors from the model under actual peak weather conditions, and the gray line shows the normalized peak load factors under normalized seasonal peak weather conditions.

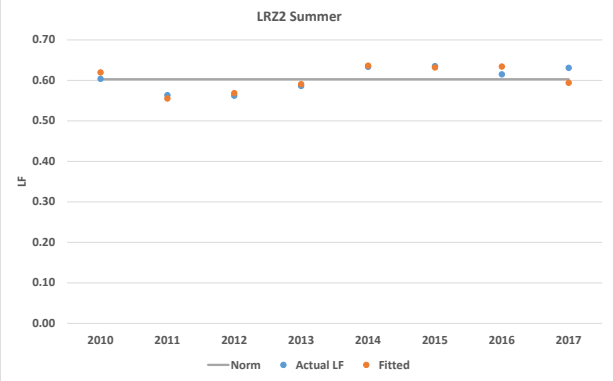
PEAK DEMAND MODELS

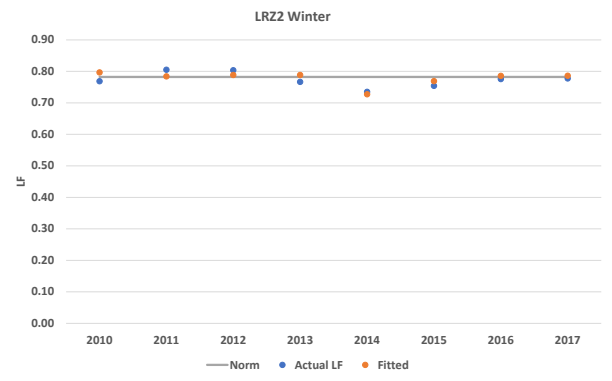
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 1



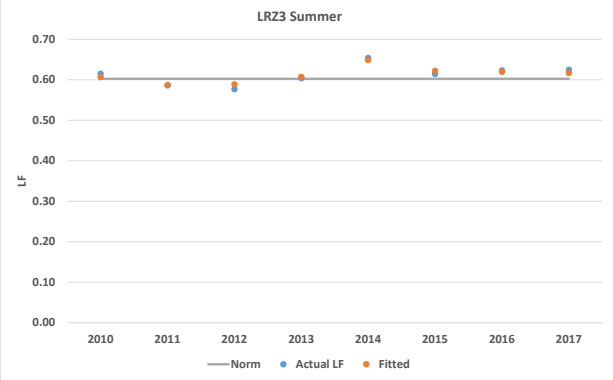


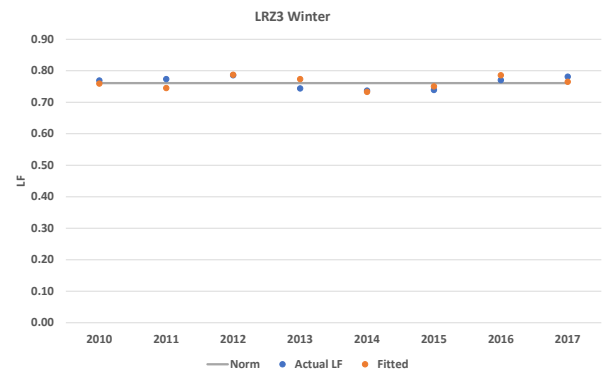
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 2



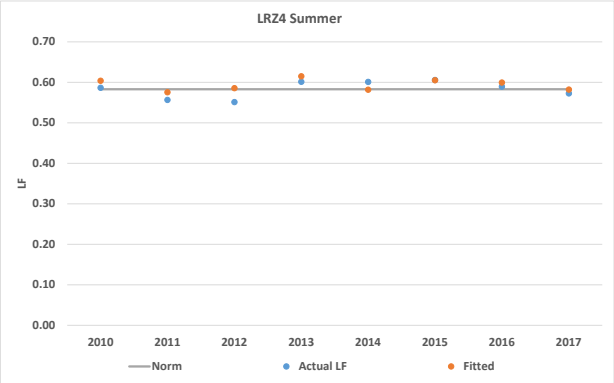


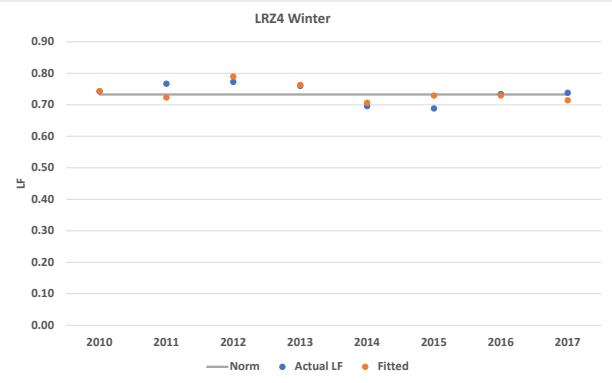
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 3



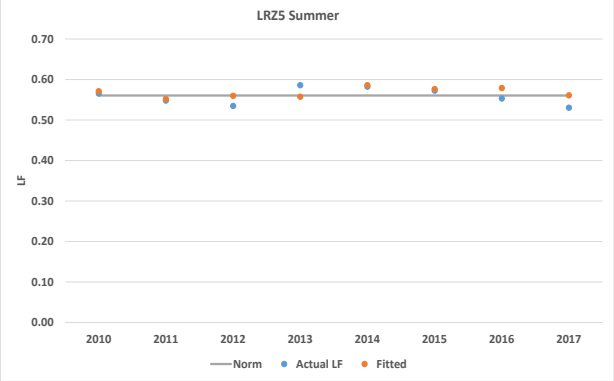


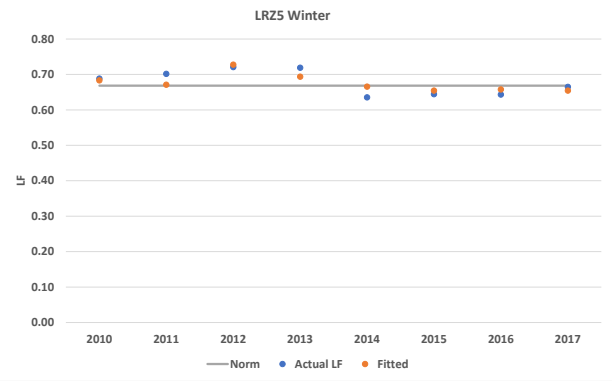
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 4



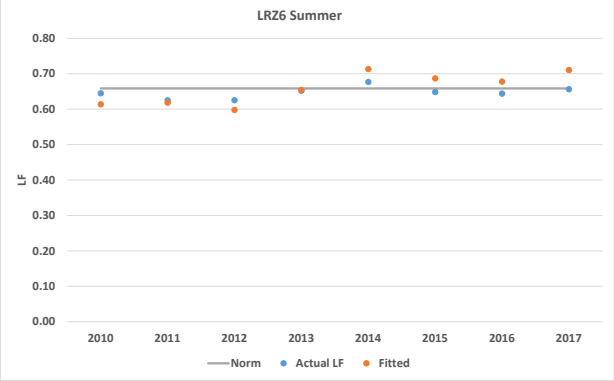


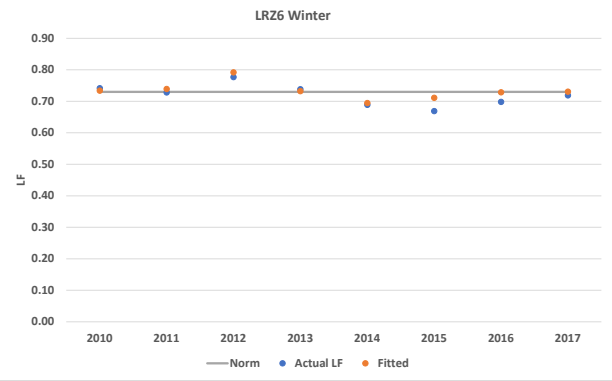
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 5



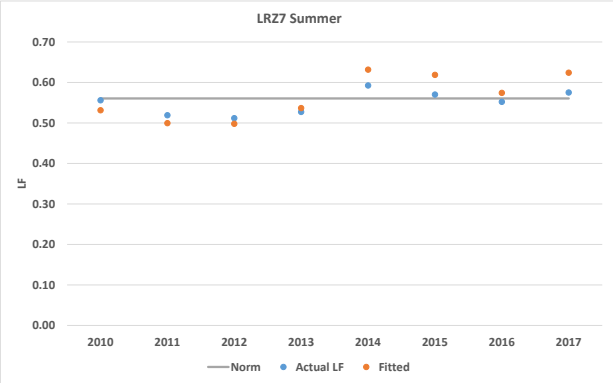


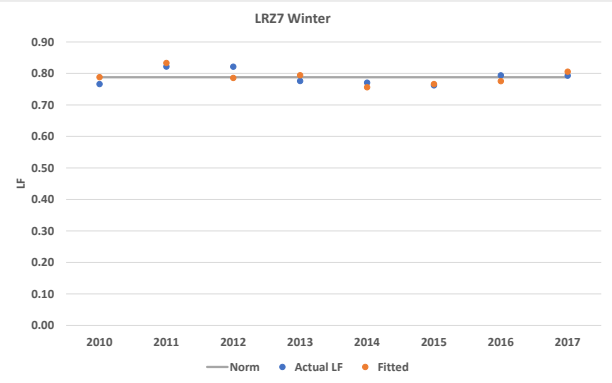
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 6



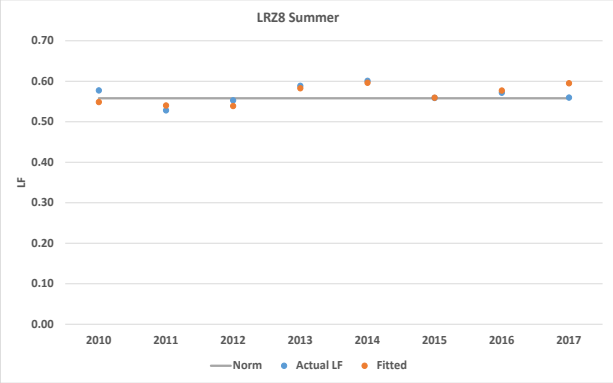


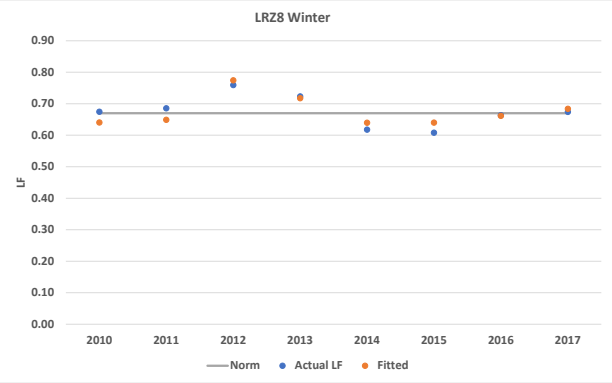
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 7



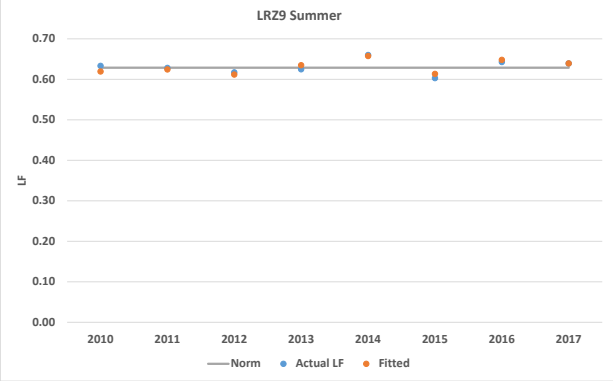


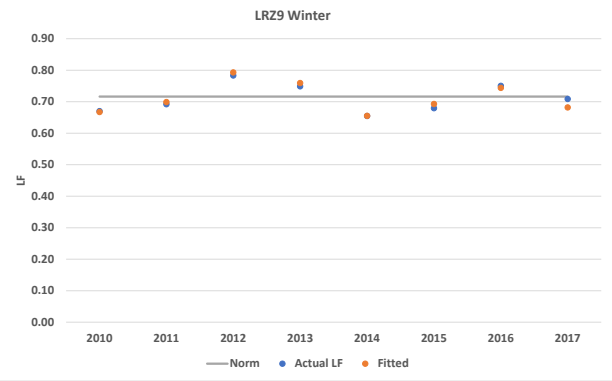
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 8



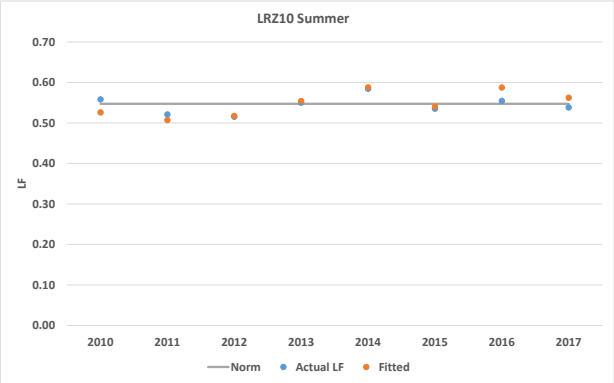


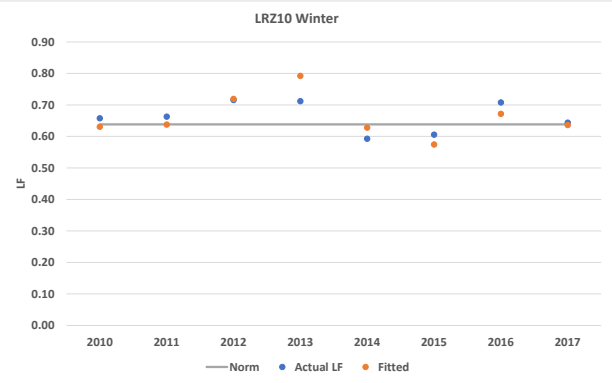
Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 9





Actual Peak Load Factors vs. Fitted Peak Load Factors for LRZ 10





APPENDIX D Weather Normalization Methodology

Starting in 2016, SUFG has used the models developed in the load forecasting process to remove the effects of weather variation from historical MISO loads. The weather normalization facilitates a comparison of load forecasts to historical loads. In the weather normalization process, the historical loads are adjusted based on the difference between the actual values of the weather variables and their longer term normal values. These differences are then multiplied by the coefficients of the variables in the forecasting models to find the changes in load that would have occurred if normal conditions had been in place. In this case, the weather variables are annual cooling degree days and heating degree days at the state level for the annual energy data and temperature at the LRZ level for peak demand data. Weather normalization has been performed for each year of historical MISO data (2011-2017). Results are shown in Tables 71 through Table 74.

Table 71: Normalized LRZ Energy (Annual Metered Load in GWh)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	95,438	64,517	45,673	49,416	42,372	99,796	100,046	36,121	101,273	20,605
2012	95,926	64,704	45,984	49,517	42,425	100,719	101,791	35,899	103,862	22,871
2013	95,898	64,402	46,273	49,716	42,797	100,060	99,341	36,052	105,947	22,684
2014	98,634	65,080	47,302	50,081	42,758	100,404	99,564	37,070	109,845	21,475
2015	96,734	64,820	47,324	49,429	42,200	98,449	99,820	36,748	109,062	22,211
2016	97,389	64,922	47,758	48,877	38,404	95,629	101,238	36,542	110,046	22,078
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245

Table 72: Normalized Summer Non-Coincident Peak Demand (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	16,938	12,282	8,615	9,704	8,865	17,428	20,508	7,064	19,289	4,742
2012	17,505	12,325	8,620	9,287	8,351	17,436	20,336	6,707	18,364	4,748
2013	17,504	12,270	8,814	9,831	8,447	17,246	20,667	7,416	19,795	4,738
2014	17,545	12,494	8,538	9,453	8,603	18,153	21,408	7,489	20,399	4,646
2015	17,531	12,297	8,759	9,439	8,423	17,586	21,170	7,468	20,464	4,638
2016	18,198	12,657	8,864	9,522	8,192	16,692	20,568	7,595	20,132	4,760
2017	17,079	11,438	8,943	9,122	7,662	16,523	20,766	7,849	20,418	4,695

Table 73: Normalized Winter Non-Coincident Peak Demand (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2011	14,376	9,366	6,727	7,526	7,379	15,809	14,759	6,165	17,114	3,765
2012	13,871	9,472	6,890	7,612	7,065	15,317	14,307	5,765	15,937	3,567
2013	14,697	9,932	7,262	7,766	7,100	15,417	14,692	6,133	16,373	3,993
2014	15,052	9,865	7,156	7,710	6,935	16,261	14,213	6,773	17,519	4,187
2015	15,220	9,794	7,152	8,012	7,514	15,961	14,906	6,727	17,983	4,053
2016	14,501	9,727	7,634	7,639	6,685	15,403	14,466	6,535	17,684	4,448
2017	14,660	9,449	7,154	7,141	6,351	14,511	14,487	5,812	16,798	3,845

Table 74: Normalized MISO System Energy and Peak Demand (Metered Load)

Year	System Energy (GWh)	System Peak (MW)	
		Summer	Winter
2011	655,255	121,443	100,220
2012	663,697	118,103	95,982
2013	663,171	121,291	98,372
2014	672,212	121,069	103,938
2015	666,798	121,787	104,371
2016	662,882	121,952	101,665
2017	665,862	122,022	97,224

APPENDIX E High and Low Forecasts

Gross State Energy Forecasts (Annual Retail Sales in GWh)—High

Year	AR	IL	IN	IA	KY	LA	MI	MN
1990	27,365	111,577	73,982	29,437	61,097	63,826	82,367	47,167
1991	28,440	116,869	77,034	30,781	64,194	64,704	84,519	48,755
1992	28,451	112,521	76,977	30,208	67,068	65,098	83,840	47,412
1993	31,663	117,786	81,931	32,104	68,149	67,756	87,589	49,211
1994	32,619	121,490	83,808	33,039	72,485	70,132	91,160	51,155
1995	34,671	126,231	87,006	34,301	74,548	72,827	94,701	53,959
1996	36,137	125,990	88,901	34,999	77,019	75,269	96,302	54,942
1997	36,858	126,953	89,147	36,148	76,836	75,886	97,391	55,674
1998	39,315	131,697	92,059	37,318	75,850	77,716	100,506	56,744
1999	39,789	132,682	96,735	38,034	79,098	78,267	103,981	57,399
2000	41,611	134,697	97,775	39,088	78,316	80,690	104,772	59,782
2001	41,732	136,034	97,734	39,444	79,975	74,693	102,409	60,687
2002	42,450	138,447	101,429	40,898	87,267	79,261	104,714	62,162
2003	43,108	136,248	100,468	41,207	85,220	77,769	108,877	63,087
2004	43,672	139,254	103,094	40,903	86,521	79,737	106,606	63,340
2005	46,165	144,986	106,549	42,757	89,351	77,389	110,445	66,019
2006	46,636	142,448	105,664	43,337	88,743	77,468	108,018	66,770
2007	47,055	146,055	109,420	45,270	92,404	79,567	109,297	68,231
2008	46,135	144,620	106,981	45,488	93,428	78,726	105,781	68,794
2009	43,173	136,688	99,312	43,641	88,897	78,670	98,121	64,004
2010	48,194	144,761	105,994	45,445	93,569	85,080	103,649	67,800
2011	47,928	142,886	105,818	45,655	89,538	86,369	105,054	68,533
2012	46,860	143,540	105,173	45,709	89,048	84,731	104,818	67,989
2013	46,683	141,805	105,487	46,705	84,764	85,808	103,038	68,644
2014	47,080	141,540	106,943	47,202	78,839	90,628	103,314	68,719
2015	46,465	138,620	104,515	47,147	76,039	91,676	102,480	66,579
2016	46,188	141,050	103,705	48,431	74,554	91,453	104,468	66,546
2017	49,009	142,761	110,415	48,120	78,430	91,161	108,061	68,766
2018	50,247	147,185	114,202	49,020	80,167	93,055	110,672	70,634
2019	51,558	148,621	117,057	51,518	82,740	96,330	111,971	71,742
2020	52,672	149,686	119,216	52,793	84,249	97,688	114,614	73,003
2021	53,573	152,720	121,015	54,208	85,820	98,086	116,628	73,656
2022	54,472	152,180	122,994	55,220	87,170	98,610	117,660	74,188
2023	55,374	154,012	125,159	55,989	88,594	99,440	117,830	75,112
2024	56,221	154,289	127,192	56,908	89,977	99,979	118,710	76,252
2025	57,032	155,108	129,049	57,992	91,213	100,479	120,139	77,213
2026	57,792	155,982	131,201	59,038	92,303	100,859	121,658	77,971
2027	58,517	156,829	133,309	59,890	93,311	101,109	123,118	78,721
2028	59,288	157,705	135,480	60,816	94,272	101,677	124,333	79,527
2029	60,125	158,694	137,522	61,840	95,195	102,222	125,821	80,253
2030	60,988	159,679	139,721	62,871	96,039	102,805	127,330	80,993
2031	61,782	160,438	141,916	63,950	96,848	103,417	128,724	81,625
2032	62,585	161,461	144,087	64,944	97,557	104,053	130,083	82,019
2033	63,411	162,865	146,453	65,902	98,287	104,678	131,476	82,443
2034	64,259	163,496	148,725	66,862	99,017	105,316	132,801	82,932
2035	65,136	164,364	151,024	67,944	99,791	105,934	134,126	83,517
2036	66,029	165,342	153,311	69,084	100,591	106,595	135,570	84,118
2037	66,910	166,288	155,761	70,104	101,355	107,335	136,906	84,678
2038	67,843	167,355	157,828	71,198	102,136	107,993	138,326	85,210
Compound Annual Growth Rates (%)								
2019-2023	1.80	0.89	1.69	2.10	1.72	0.80	1.28	1.15
2019-2028	1.56	0.66	1.64	1.86	1.46	0.60	1.17	1.15
2019-2038	1.46	0.63	1.59	1.72	1.11	0.60	1.12	0.91

Gross State Energy Forecasts (Annual Retail Sales in GWh)—High - continued

Year	MS	MO	MT	ND	SD	TX	WI
1990	32,127	53,925	13,125	7,014	6,334	237,415	49,198
1991	33,019	56,514	13,407	7,255	6,685	240,352	51,032
1992	33,241	54,411	13,096	7,128	6,494	239,431	50,925
1993	34,749	58,622	12,929	7,432	6,905	250,084	53,156
1994	36,627	59,693	13,184	7,681	7,174	258,180	55,412
1995	37,868	62,259	13,419	7,883	7,414	263,279	57,967
1996	39,622	64,843	13,820	8,314	7,736	278,450	58,744
1997	40,089	65,711	11,917	8,282	7,773	286,704	60,094
1998	42,510	69,010	14,145	8,220	7,824	304,705	62,061
1999	43,980	69,045	13,282	9,112	7,922	301,844	63,547
2000	45,336	72,643	14,580	9,413	8,283	318,263	65,146
2001	44,287	73,213	11,447	9,810	8,627	318,044	65,218
2002	45,452	75,001	12,831	10,219	8,937	320,846	66,999
2003	45,544	74,240	12,825	10,461	9,080	322,686	67,241
2004	46,033	74,054	12,957	10,516	9,214	320,615	67,976
2005	45,901	80,940	13,479	10,840	9,811	334,258	70,336
2006	46,936	82,015	13,815	11,245	10,056	342,724	69,821
2007	48,153	85,533	15,532	11,906	10,603	343,829	71,301
2008	47,721	84,382	15,326	12,416	10,974	347,815	70,122
2009	46,049	79,897	14,354	12,649	11,010	345,351	66,286
2010	49,687	86,085	13,771	12,956	11,356	358,458	68,752
2011	49,338	84,255	13,788	13,737	11,680	376,065	68,612
2012	48,388	82,435	13,863	14,717	11,734	365,104	68,820
2013	48,782	83,407	14,045	16,033	12,210	378,817	69,124
2014	49,409	83,878	14,102	18,240	12,355	389,670	69,495
2015	48,692	81,504	14,207	18,129	12,102	392,337	68,699
2016	49,050	78,618	14,101	18,520	12,130	398,662	69,736
2017	51,570	83,888	17,095	19,193	12,743	405,532	72,571
2018	53,823	85,775	18,284	19,734	13,088	416,522	74,123
2019	55,610	87,484	19,955	21,095	13,680	437,285	75,647
2020	57,064	89,422	21,028	22,196	14,086	446,974	76,748
2021	58,385	91,313	21,798	23,411	14,499	455,469	77,654
2022	59,683	92,795	22,362	24,309	14,800	464,971	78,717
2023	60,977	94,259	22,770	25,102	15,071	474,803	79,618
2024	62,121	95,696	23,117	25,955	15,400	483,728	80,375
2025	63,151	97,130	23,429	26,886	15,765	492,485	81,246
2026	64,103	98,715	23,795	27,765	16,116	500,674	82,153
2027	65,031	100,224	24,080	28,409	16,421	509,188	83,144
2028	65,938	101,505	24,288	28,977	16,713	518,364	84,208
2029	66,918	102,744	24,583	29,713	17,004	528,825	85,355
2030	67,944	103,908	24,909	30,216	17,298	538,919	86,426
2031	68,892	104,984	25,112	30,781	17,576	549,290	87,600
2032	69,823	105,953	25,405	31,332	17,837	559,670	88,655
2033	70,729	106,903	25,741	31,750	18,060	570,568	89,598
2034	71,722	107,815	26,170	32,174	18,274	581,758	90,645
2035	72,706	108,767	26,638	32,620	18,510	592,866	91,666
2036	73,721	109,707	27,012	33,077	18,767	604,520	92,704
2037	74,709	110,732	27,428	33,563	19,030	616,290	93,777
2038	75,707	111,763	27,759	34,010	19,277	628,841	94,806
Compound Annual Growth Rates (%)							
2019-2023	2.33	1.88	3.35	4.44	2.45	2.08	1.29
2019-2028	1.91	1.67	2.21	3.59	2.25	1.91	1.20
2019-2038	1.64	1.30	1.75	2.55	1.82	1.93	1.20

HIGH AND LOW FORECASTS

Gross LRZ Energy Forecasts (Annual Metered Load in GWh) —High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	100,827	65,959	49,996	49,457	39,018	97,447	102,335	38,713	115,715	23,217
2019	103,500	67,268	52,427	49,939	39,524	100,167	103,536	39,723	120,150	23,988
2020	105,868	68,296	53,682	50,297	40,174	102,007	105,980	40,581	122,052	24,615
2021	107,534	69,134	55,095	51,317	40,782	103,696	107,842	41,276	122,947	25,184
2022	108,878	70,053	56,065	51,135	41,156	105,365	108,797	41,969	124,023	25,744
2023	110,472	70,799	56,841	51,751	41,505	107,164	108,954	42,663	125,419	26,303
2024	112,271	71,460	57,741	51,844	41,863	108,877	109,768	43,317	126,477	26,796
2025	113,942	72,242	58,806	52,119	42,230	110,428	111,089	43,942	127,485	27,241
2026	115,416	73,057	59,833	52,413	42,649	112,053	112,493	44,527	128,344	27,651
2027	116,763	73,937	60,674	52,697	43,030	113,615	113,843	45,086	129,094	28,051
2028	118,120	74,866	61,585	52,992	43,339	115,186	114,967	45,680	130,195	28,443
2029	119,508	75,876	62,592	53,324	43,645	116,672	116,343	46,325	131,349	28,865
2030	120,824	76,824	63,605	53,655	43,906	118,198	117,738	46,990	132,519	29,308
2031	122,024	77,852	64,659	53,910	44,114	119,704	119,028	47,602	133,734	29,717
2032	122,991	78,781	65,634	54,254	44,270	121,148	120,284	48,221	134,972	30,119
2033	123,924	79,619	66,578	54,726	44,398	122,699	121,572	48,858	136,231	30,509
2034	124,975	80,539	67,514	54,938	44,493	124,205	122,797	49,511	137,519	30,938
2035	126,147	81,438	68,572	55,229	44,622	125,746	124,022	50,187	138,784	31,362
2036	127,312	82,356	69,687	55,558	44,732	127,293	125,357	50,875	140,123	31,800
2037	128,468	83,299	70,686	55,876	44,875	128,904	126,592	51,554	141,545	32,226
2038	129,542	84,208	71,759	56,234	45,014	130,332	127,906	52,273	142,934	32,657
Compound Annual Growth Rates (%)										
2019-2023	1.64	1.29	2.04	0.89	1.23	1.70	1.28	1.80	1.08	2.33
2019-2028	1.48	1.20	1.80	0.66	1.03	1.56	1.17	1.56	0.90	1.91
2019-2038	1.19	1.19	1.67	0.63	0.69	1.40	1.12	1.46	0.92	1.64

HIGH AND LOW FORECASTS

Net LRZ Energy Forecasts (Annual Metered Load in GWh) —High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	100,701	65,714	49,670	49,267	38,970	97,366	102,190	38,560	115,663	23,217
2019	103,256	66,775	51,769	49,521	39,426	100,013	103,230	39,416	120,066	23,988
2020	105,503	67,552	52,687	49,657	40,002	101,776	105,511	40,118	121,933	24,615
2021	107,050	68,142	53,836	50,452	40,527	103,396	107,210	40,656	122,789	25,184
2022	108,272	68,815	54,537	50,046	40,810	104,997	107,999	41,191	123,825	25,744
2023	109,743	69,318	55,039	50,435	41,065	106,729	107,987	41,729	125,181	26,303
2024	111,417	69,740	55,667	50,301	41,330	108,376	108,630	42,226	126,200	26,796
2025	112,961	70,286	56,472	50,348	41,612	109,863	109,786	42,696	127,169	27,241
2026	114,306	70,869	57,235	50,475	41,948	111,426	111,027	43,127	127,987	27,651
2027	115,523	71,522	57,808	50,649	42,244	112,927	112,213	43,532	128,695	28,051
2028	116,747	72,229	58,450	50,833	42,474	114,439	113,174	43,974	129,754	28,443
2029	118,001	73,021	59,194	51,062	42,704	115,869	114,389	44,468	130,866	28,865
2030	119,182	73,757	59,942	51,289	42,890	117,338	115,621	44,982	131,993	29,308
2031	120,247	74,706	60,726	51,440	43,023	118,789	116,744	45,444	133,165	29,717
2032	121,076	75,557	61,428	51,680	43,101	120,180	117,831	45,913	134,360	30,119
2033	121,868	76,319	62,095	52,048	43,151	121,680	118,948	46,402	135,574	30,509
2034	122,774	77,162	62,783	52,156	43,165	123,134	119,995	46,908	136,818	30,938
2035	123,798	77,983	63,589	52,343	43,210	124,624	121,037	47,437	138,038	31,362
2036	124,812	78,824	64,450	52,568	43,236	126,121	122,185	47,981	139,331	31,800
2037	125,816	79,689	65,193	52,783	43,291	127,684	123,233	48,516	140,708	32,226
2038	126,737	80,529	66,014	53,044	43,345	129,065	124,357	49,100	142,053	32,657
Compound Annual Growth Rates (%)										
2019-2023	1.53	0.94	1.54	0.46	1.02	1.64	1.13	1.44	1.05	2.33
2019-2028	1.37	0.88	1.36	0.29	0.83	1.51	1.03	1.22	0.87	1.91
2019-2038	1.08	0.99	1.29	0.36	0.50	1.35	0.98	1.16	0.89	1.64

HIGH AND LOW FORECASTS

Gross Summer Non-Coincident Peak Demand (Metered Load in MW) —High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	18,017	12,492	9,475	9,686	7,946	16,894	20,843	7,921	21,019	4,844
2019	18,494	12,740	9,935	9,780	8,050	17,366	21,088	8,128	21,825	5,005
2020	18,917	12,935	10,173	9,850	8,182	17,685	21,585	8,303	22,171	5,136
2021	19,215	13,093	10,441	10,050	8,306	17,978	21,965	8,445	22,333	5,255
2022	19,455	13,268	10,625	10,014	8,382	18,267	22,159	8,587	22,529	5,372
2023	19,740	13,409	10,772	10,135	8,453	18,579	22,191	8,729	22,782	5,488
2024	20,061	13,534	10,943	10,153	8,526	18,876	22,357	8,863	22,974	5,591
2025	20,360	13,682	11,144	10,207	8,601	19,145	22,626	8,991	23,158	5,684
2026	20,624	13,836	11,339	10,265	8,686	19,426	22,912	9,110	23,314	5,770
2027	20,864	14,003	11,498	10,320	8,764	19,697	23,187	9,225	23,450	5,853
2028	21,107	14,179	11,671	10,378	8,826	19,969	23,416	9,346	23,650	5,935
2029	21,355	14,370	11,862	10,443	8,889	20,227	23,696	9,478	23,859	6,023
2030	21,590	14,550	12,054	10,508	8,942	20,492	23,980	9,614	24,072	6,115
2031	21,804	14,745	12,253	10,558	8,984	20,753	24,243	9,740	24,293	6,201
2032	21,977	14,921	12,438	10,625	9,016	21,003	24,499	9,866	24,517	6,285
2033	22,144	15,079	12,617	10,718	9,042	21,272	24,761	9,997	24,746	6,366
2034	22,332	15,254	12,795	10,759	9,061	21,533	25,011	10,130	24,980	6,455
2035	22,541	15,424	12,995	10,816	9,088	21,800	25,260	10,268	25,210	6,544
2036	22,749	15,598	13,206	10,881	9,110	22,068	25,532	10,409	25,453	6,635
2037	22,956	15,776	13,396	10,943	9,139	22,348	25,784	10,548	25,711	6,724
2038	23,148	15,949	13,599	11,013	9,168	22,595	26,051	10,695	25,964	6,814
Compound Annual Growth Rates (%)										
2019-2023	1.64	1.29	2.04	0.89	1.23	1.70	1.28	1.80	1.08	2.33
2019-2028	1.48	1.20	1.80	0.66	1.03	1.56	1.17	1.56	0.90	1.91
2019-2038	1.19	1.19	1.67	0.63	0.69	1.40	1.12	1.46	0.92	1.64

HIGH AND LOW FORECASTS

Gross Winter Non-Coincident Peak Demand (Metered Load in MW) —High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	15,265	9,625	7,503	7,702	6,663	15,239	14,829	6,597	18,438	4,152
2019	15,669	9,816	7,868	7,778	6,750	15,665	15,003	6,769	19,145	4,290
2020	16,028	9,966	8,057	7,833	6,861	15,952	15,357	6,916	19,448	4,402
2021	16,280	10,088	8,269	7,992	6,965	16,216	15,627	7,034	19,591	4,504
2022	16,484	10,222	8,414	7,964	7,028	16,477	15,765	7,152	19,762	4,604
2023	16,725	10,331	8,531	8,060	7,088	16,759	15,788	7,270	19,984	4,704
2024	16,997	10,427	8,666	8,074	7,149	17,027	15,906	7,382	20,153	4,792
2025	17,250	10,541	8,826	8,117	7,212	17,269	16,097	7,488	20,314	4,871
2026	17,473	10,660	8,980	8,163	7,283	17,523	16,300	7,588	20,450	4,945
2027	17,677	10,789	9,106	8,207	7,349	17,768	16,496	7,683	20,570	5,016
2028	17,883	10,924	9,243	8,253	7,401	18,013	16,659	7,785	20,745	5,086
2029	18,093	11,072	9,394	8,305	7,454	18,246	16,858	7,895	20,929	5,162
2030	18,292	11,210	9,546	8,356	7,498	18,484	17,061	8,008	21,116	5,241
2031	18,474	11,360	9,704	8,396	7,534	18,720	17,247	8,112	21,309	5,314
2032	18,620	11,496	9,850	8,450	7,560	18,946	17,429	8,218	21,507	5,386
2033	18,762	11,618	9,992	8,523	7,582	19,188	17,616	8,326	21,707	5,456
2034	18,921	11,752	10,133	8,556	7,598	19,424	17,794	8,437	21,912	5,532
2035	19,098	11,883	10,291	8,601	7,620	19,665	17,971	8,553	22,114	5,608
2036	19,274	12,017	10,459	8,653	7,639	19,907	18,164	8,670	22,327	5,687
2037	19,450	12,155	10,609	8,702	7,663	20,159	18,343	8,785	22,554	5,763
2038	19,612	12,288	10,770	8,758	7,687	20,382	18,534	8,908	22,775	5,840
Compound Annual Growth Rates (%)										
2019-2023	1.64	1.29	2.04	0.89	1.23	1.70	1.28	1.80	1.08	2.33
2019-2028	1.48	1.20	1.80	0.66	1.03	1.56	1.17	1.56	0.90	1.91
2019-2038	1.19	1.19	1.67	0.63	0.69	1.40	1.12	1.46	0.92	1.64

HIGH AND LOW FORECASTS

Net Summer Non-Coincident Peak Demand (Metered Load in MW) —High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,986	12,432	9,397	9,640	7,933	16,873	20,807	7,886	21,007	4,844
2019	18,436	12,619	9,779	9,680	8,023	17,326	21,012	8,058	21,805	5,005
2020	18,830	12,752	9,937	9,696	8,136	17,626	21,470	8,199	22,142	5,136
2021	19,099	12,849	10,143	9,842	8,237	17,900	21,809	8,305	22,295	5,255
2022	19,310	12,963	10,263	9,752	8,289	18,172	21,963	8,412	22,481	5,372
2023	19,566	13,044	10,345	9,818	8,335	18,467	21,954	8,519	22,725	5,488
2024	19,857	13,110	10,451	9,782	8,383	18,747	22,077	8,617	22,907	5,591
2025	20,126	13,200	10,592	9,781	8,435	19,000	22,306	8,710	23,081	5,684
2026	20,358	13,297	10,724	9,798	8,498	19,266	22,552	8,795	23,227	5,770
2027	20,568	13,408	10,820	9,827	8,553	19,521	22,787	8,875	23,353	5,853
2028	20,779	13,529	10,929	9,858	8,595	19,778	22,975	8,962	23,543	5,935
2029	20,994	13,667	11,058	9,899	8,637	20,021	23,216	9,059	23,742	6,023
2030	21,198	13,794	11,187	9,939	8,670	20,271	23,460	9,161	23,944	6,115
2031	21,380	13,969	11,324	9,964	8,692	20,518	23,682	9,253	24,154	6,201
2032	21,520	14,125	11,444	10,007	8,703	20,755	23,897	9,346	24,369	6,285
2033	21,653	14,265	11,558	10,074	8,708	21,011	24,117	9,443	24,587	6,366
2034	21,806	14,420	11,677	10,091	8,705	21,258	24,323	9,543	24,810	6,455
2035	21,980	14,571	11,818	10,123	8,709	21,512	24,527	9,649	25,028	6,544
2036	22,152	14,726	11,970	10,163	8,708	21,768	24,753	9,757	25,261	6,635
2037	22,323	14,885	12,100	10,200	8,714	22,035	24,959	9,864	25,508	6,724
2038	22,477	15,038	12,243	10,246	8,718	22,270	25,180	9,979	25,749	6,814
Compound Annual Growth Rates (%)										
2019-2023	1.50	0.83	1.42	0.36	0.96	1.61	1.10	1.40	1.04	2.33
2019-2028	1.34	0.78	1.24	0.20	0.77	1.48	1.00	1.19	0.86	1.91
2019-2038	1.05	0.93	1.19	0.30	0.44	1.33	0.96	1.13	0.88	1.64

HIGH AND LOW FORECASTS

Net Winter Non-Coincident Peak Demand (Metered Load in MW)—High

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	15,234	9,564	7,426	7,657	6,650	15,218	14,793	6,563	18,426	4,152
2019	15,611	9,694	7,712	7,677	6,723	15,625	14,927	6,700	19,125	4,290
2020	15,941	9,783	7,821	7,679	6,815	15,893	15,241	6,811	19,419	4,402
2021	16,164	9,844	7,970	7,784	6,896	16,139	15,471	6,894	19,552	4,504
2022	16,339	9,917	8,052	7,701	6,936	16,383	15,569	6,977	19,714	4,604
2023	16,551	9,966	8,104	7,743	6,971	16,647	15,550	7,060	19,927	4,704
2024	16,793	10,004	8,175	7,703	7,007	16,898	15,626	7,136	20,086	4,792
2025	17,016	10,060	8,273	7,690	7,047	17,124	15,777	7,207	20,237	4,871
2026	17,208	10,121	8,365	7,696	7,096	17,362	15,940	7,272	20,364	4,945
2027	17,381	10,194	8,428	7,714	7,138	17,591	16,096	7,333	20,473	5,016
2028	17,555	10,274	8,501	7,733	7,169	17,822	16,219	7,400	20,638	5,086
2029	17,733	10,368	8,590	7,760	7,202	18,040	16,379	7,476	20,812	5,162
2030	17,900	10,454	8,679	7,787	7,226	18,264	16,541	7,555	20,988	5,241
2031	18,049	10,584	8,774	7,802	7,241	18,485	16,687	7,625	21,171	5,314
2032	18,163	10,700	8,856	7,831	7,247	18,697	16,827	7,697	21,358	5,386
2033	18,270	10,804	8,932	7,880	7,248	18,927	16,972	7,772	21,548	5,456
2034	18,395	10,919	9,015	7,888	7,242	19,149	17,106	7,850	21,742	5,532
2035	18,537	11,030	9,115	7,908	7,241	19,377	17,238	7,933	21,933	5,608
2036	18,678	11,145	9,223	7,935	7,237	19,606	17,386	8,017	22,135	5,687
2037	18,816	11,263	9,313	7,960	7,238	19,846	17,519	8,101	22,350	5,763
2038	18,942	11,377	9,413	7,991	7,238	20,057	17,663	8,192	22,561	5,840
Compound Annual Growth Rates (%)										
2019-2023	1.47	0.69	1.25	0.21	0.91	1.60	1.03	1.32	1.03	2.33
2019-2028	1.31	0.65	1.09	0.08	0.72	1.47	0.93	1.11	0.85	1.91
2019-2038	1.02	0.85	1.05	0.21	0.39	1.32	0.89	1.06	0.87	1.64

HIGH AND LOW FORECASTS

Gross and Net MISO System Energy (Annual Metered Load in GWh) —High

Year	MISO Energy without EE Adjustments	MISO Energy with EE Adjustments
2017	665,862	665,862
2018	682,684	681,317
2019	700,224	697,460
2020	713,552	709,354
2021	724,808	719,241
2022	733,186	726,237
2023	741,871	733,531
2024	750,413	740,683
2025	759,523	748,433
2026	768,436	756,050
2027	776,791	763,166
2028	785,373	770,517
2029	794,501	778,439
2030	803,567	786,303
2031	812,343	794,002
2032	820,672	801,244
2033	829,114	808,593
2034	837,430	815,832
2035	846,108	823,420
2036	855,093	831,308
2037	864,025	839,139
2038	872,859	846,902
Compound Annual Growth Rates (%)		
2019-2023	1.45	1.27
2019-2028	1.28	1.11
2019-2038	1.17	1.03

HIGH AND LOW FORECASTS

Gross and Net MISO System Coincident Peak Demand (Metered Load in MW) —High

Year	MISO Summer CP without EE Adjustments	MISO Summer CP with EE Adjustments	MISO Winter CP without EE Adjustments	MISO Winter CP with EE Adjustments
2017	120,779	120,779	99,870	99,870
2018	123,821	123,503	102,397	102,076
2019	126,950	126,306	105,037	104,387
2020	129,368	128,390	107,032	106,044
2021	131,425	130,127	108,724	107,413
2022	132,935	131,314	109,987	108,350
2023	134,486	132,540	111,310	109,345
2024	136,018	133,746	112,600	110,307
2025	137,665	135,076	113,967	111,353
2026	139,281	136,390	115,303	112,384
2027	140,798	137,617	116,556	113,345
2028	142,348	138,880	117,843	114,342
2029	144,002	140,253	119,210	115,425
2030	145,645	141,617	120,568	116,500
2031	147,233	142,955	121,880	117,560
2032	148,743	144,213	123,126	118,552
2033	150,272	145,490	124,390	119,559
2034	151,775	146,743	125,634	120,551
2035	153,343	148,058	126,933	121,595
2036	154,969	149,430	128,277	122,682
2037	156,581	150,787	129,615	123,761
2038	158,182	152,132	130,937	124,825
Compound Annual Growth Rates (%)				
2019-2023	1.45	1.21	1.46	1.17
2019-2028	1.28	1.06	1.29	1.02
2019-2038	1.16	0.98	1.17	0.95

HIGH AND LOW FORECASTS

Gross State Energy Forecasts (Annual Retail Sales in GWh) —Low

Year	AR	IL	IN	IA	KY	LA	MI	MN
1990	27,365	111,577	73,982	29,437	61,097	63,826	82,367	47,167
1991	28,440	116,869	77,034	30,781	64,194	64,704	84,519	48,755
1992	28,451	112,521	76,977	30,208	67,068	65,098	83,840	47,412
1993	31,663	117,786	81,931	32,104	68,149	67,756	87,589	49,211
1994	32,619	121,490	83,808	33,039	72,485	70,132	91,160	51,155
1995	34,671	126,231	87,006	34,301	74,548	72,827	94,701	53,959
1996	36,137	125,990	88,901	34,999	77,019	75,269	96,302	54,942
1997	36,858	126,953	89,147	36,148	76,836	75,886	97,391	55,674
1998	39,315	131,697	92,059	37,318	75,850	77,716	100,506	56,744
1999	39,789	132,682	96,735	38,034	79,098	78,267	103,981	57,399
2000	41,611	134,697	97,775	39,088	78,316	80,690	104,772	59,782
2001	41,732	136,034	97,734	39,444	79,975	74,693	102,409	60,687
2002	42,450	138,447	101,429	40,898	87,267	79,261	104,714	62,162
2003	43,108	136,248	100,468	41,207	85,220	77,769	108,877	63,087
2004	43,672	139,254	103,094	40,903	86,521	79,737	106,606	63,340
2005	46,165	144,986	106,549	42,757	89,351	77,389	110,445	66,019
2006	46,636	142,448	105,664	43,337	88,743	77,468	108,018	66,770
2007	47,055	146,055	109,420	45,270	92,404	79,567	109,297	68,231
2008	46,135	144,620	106,981	45,488	93,428	78,726	105,781	68,794
2009	43,173	136,688	99,312	43,641	88,897	78,670	98,121	64,004
2010	48,194	144,761	105,994	45,445	93,569	85,080	103,649	67,800
2011	47,928	142,886	105,818	45,655	89,538	86,369	105,054	68,533
2012	46,860	143,540	105,173	45,709	89,048	84,731	104,818	67,989
2013	46,683	141,805	105,487	46,705	84,764	85,808	103,038	68,644
2014	47,080	141,540	106,943	47,202	78,839	90,628	103,314	68,719
2015	46,465	138,620	104,515	47,147	76,039	91,676	102,480	66,579
2016	46,188	141,050	103,705	48,431	74,554	91,453	104,468	66,546
2017	46,100	137,907	103,205	45,945	75,675	85,796	104,340	68,347
2018	45,785	135,896	102,289	45,928	74,743	86,225	105,415	68,340
2019	45,694	135,098	101,821	45,734	74,424	83,566	105,450	68,590
2020	46,174	134,781	101,745	45,903	74,721	83,491	103,721	69,147
2021	46,322	135,047	101,512	46,522	75,399	83,266	103,341	69,273
2022	46,556	135,380	101,764	46,870	76,055	83,145	102,361	69,368
2023	46,857	135,849	102,024	47,087	76,875	83,572	100,806	69,807
2024	47,176	136,251	102,457	47,431	77,718	83,540	100,236	70,506
2025	47,476	136,649	102,929	48,025	78,437	83,607	100,277	71,037
2026	47,719	137,108	103,501	48,574	79,006	83,740	100,335	71,494
2027	47,961	137,496	104,108	49,100	79,542	83,656	100,343	71,893
2028	48,257	137,919	104,657	49,633	80,107	83,851	100,535	72,384
2029	48,653	138,503	105,483	50,110	80,604	83,983	100,683	72,749
2030	49,025	139,083	106,294	50,758	81,027	84,244	101,001	73,136
2031	49,382	139,556	107,268	51,448	81,419	84,424	101,239	73,439
2032	49,736	140,009	108,049	52,079	81,786	84,727	101,632	73,568
2033	50,133	140,081	109,194	52,599	82,176	85,004	102,057	73,745
2034	50,549	140,978	110,078	53,138	82,522	85,253	102,372	74,008
2035	51,002	141,594	111,063	53,720	82,942	85,499	102,678	74,336
2036	51,499	142,330	112,030	54,384	83,398	85,828	103,117	74,665
2037	51,983	142,902	113,268	55,104	83,833	86,234	103,507	74,897
2038	52,483	143,456	114,492	55,723	84,243	86,576	103,867	75,283
Compound Annual Growth Rates (%)								
2019-2023	0.63	0.14	0.05	0.73	0.81	0.00	-1.12	0.44
2019-2028	0.61	0.23	0.31	0.91	0.82	0.04	-0.53	0.60
2019-2038	0.73	0.32	0.62	1.05	0.65	0.19	-0.08	0.49

Gross State Energy Forecasts (Annual Retail Sales in GWh) —Low – continued

Year	MS	MO	MT	ND	SD	TX	WI
1990	32,127	53,925	13,125	7,014	6,334	237,415	49,198
1991	33,019	56,514	13,407	7,255	6,685	240,352	51,032
1992	33,241	54,411	13,096	7,128	6,494	239,431	50,925
1993	34,749	58,622	12,929	7,432	6,905	250,084	53,156
1994	36,627	59,693	13,184	7,681	7,174	258,180	55,412
1995	37,868	62,259	13,419	7,883	7,414	263,279	57,967
1996	39,622	64,843	13,820	8,314	7,736	278,450	58,744
1997	40,089	65,711	11,917	8,282	7,773	286,704	60,094
1998	42,510	69,010	14,145	8,220	7,824	304,705	62,061
1999	43,980	69,045	13,282	9,112	7,922	301,844	63,547
2000	45,336	72,643	14,580	9,413	8,283	318,263	65,146
2001	44,287	73,213	11,447	9,810	8,627	318,044	65,218
2002	45,452	75,001	12,831	10,219	8,937	320,846	66,999
2003	45,544	74,240	12,825	10,461	9,080	322,686	67,241
2004	46,033	74,054	12,957	10,516	9,214	320,615	67,976
2005	45,901	80,940	13,479	10,840	9,811	334,258	70,336
2006	46,936	82,015	13,815	11,245	10,056	342,724	69,821
2007	48,153	85,533	15,532	11,906	10,603	343,829	71,301
2008	47,721	84,382	15,326	12,416	10,974	347,815	70,122
2009	46,049	79,897	14,354	12,649	11,010	345,351	66,286
2010	49,687	86,085	13,771	12,956	11,356	358,458	68,752
2011	49,338	84,255	13,788	13,737	11,680	376,065	68,612
2012	48,388	82,435	13,863	14,717	11,734	365,104	68,820
2013	48,782	83,407	14,045	16,033	12,210	378,817	69,124
2014	49,409	83,878	14,102	18,240	12,355	389,670	69,495
2015	48,692	81,504	14,207	18,129	12,102	392,337	68,699
2016	49,050	78,618	14,101	18,520	12,130	398,662	69,736
2017	49,460	80,346	12,326	17,394	12,482	393,938	69,221
2018	49,426	80,154	11,735	17,137	12,523	399,908	69,546
2019	49,232	79,910	12,114	16,749	12,611	396,010	70,203
2020	49,492	79,844	12,045	16,798	12,803	398,928	70,632
2021	49,900	79,716	11,838	17,136	13,055	402,459	70,955
2022	50,398	79,737	11,856	17,175	13,225	408,020	71,534
2023	50,963	79,892	11,801	17,167	13,394	414,593	72,071
2024	51,517	80,211	11,728	17,185	13,631	420,741	72,552
2025	51,987	80,668	11,627	17,440	13,934	425,976	73,130
2026	52,442	81,364	11,646	17,478	14,193	431,608	73,864
2027	52,930	81,969	11,567	17,470	14,402	436,975	74,671
2028	53,448	82,435	11,587	17,440	14,617	443,637	75,537
2029	54,042	82,900	11,517	17,397	14,841	450,153	76,509
2030	54,695	83,328	11,520	17,321	15,045	457,770	77,430
2031	55,312	83,751	11,473	17,199	15,239	465,755	78,387
2032	55,878	84,129	11,448	17,019	15,405	473,058	79,253
2033	56,464	84,378	11,554	16,738	15,552	480,533	80,111
2034	57,133	84,710	11,754	16,535	15,681	488,385	80,982
2035	57,799	85,108	11,889	16,299	15,842	496,566	81,816
2036	58,492	85,491	12,066	16,176	15,993	504,484	82,725
2037	59,184	85,992	12,166	16,014	16,155	513,044	83,651
2038	59,931	86,476	12,282	15,808	16,305	522,281	84,611
Compound Annual Growth Rates (%)							
2019-2023	0.87	-0.01	-0.65	0.62	1.52	1.15	0.66
2019-2028	0.92	0.35	-0.49	0.45	1.65	1.27	0.82
2019-2038	1.04	0.42	0.07	-0.30	1.36	1.47	0.99

HIGH AND LOW FORECASTS

Gross LRZ Energy Forecasts (Annual Metered Load in GWh) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	97,705	64,897	48,997	47,271	38,068	93,699	100,950	37,502	114,027	22,230
2019	98,093	65,461	48,795	46,993	37,694	93,283	100,984	37,427	111,039	22,142
2020	98,782	65,742	48,969	46,883	37,452	93,400	99,328	37,820	111,145	22,259
2021	99,094	65,999	49,598	46,976	37,172	93,635	98,963	37,941	111,134	22,443
2022	99,364	66,446	49,956	47,092	36,923	94,116	98,025	38,133	111,358	22,667
2023	99,930	66,828	50,188	47,255	36,729	94,687	96,536	38,380	112,211	22,921
2024	100,778	67,211	50,550	47,394	36,635	95,362	95,991	38,641	112,564	23,170
2025	101,571	67,708	51,162	47,533	36,618	95,993	96,029	38,887	112,961	23,381
2026	102,268	68,340	51,728	47,692	36,702	96,597	96,085	39,087	113,452	23,586
2027	102,851	69,032	52,268	47,828	36,744	97,202	96,093	39,285	113,701	23,806
2028	103,569	69,784	52,817	47,975	36,748	97,791	96,277	39,528	114,320	24,039
2029	104,138	70,624	53,311	48,178	36,768	98,492	96,418	39,853	114,865	24,306
2030	104,734	71,429	53,976	48,379	36,762	99,145	96,723	40,157	115,612	24,599
2031	105,213	72,261	54,680	48,544	36,743	99,868	96,951	40,450	116,298	24,877
2032	105,474	73,022	55,323	48,702	36,700	100,476	97,327	40,740	117,069	25,131
2033	105,789	73,779	55,850	48,727	36,587	101,288	97,734	41,065	117,824	25,395
2034	106,255	74,541	56,408	49,039	36,499	101,939	98,036	41,406	118,573	25,696
2035	106,752	75,271	57,006	49,253	36,455	102,683	98,329	41,778	119,340	25,995
2036	107,323	76,072	57,687	49,509	36,395	103,436	98,750	42,184	120,176	26,307
2037	107,756	76,885	58,422	49,708	36,385	104,321	99,122	42,581	121,131	26,619
2038	108,339	77,726	59,057	49,900	36,365	105,186	99,467	42,991	122,063	26,954
Compound Annual Growth Rates (%)										
2019-2023	0.46	0.52	0.71	0.14	-0.65	0.37	-1.12	0.63	0.26	0.87
2019-2028	0.61	0.71	0.88	0.23	-0.28	0.53	-0.53	0.61	0.32	0.92
2019-2038	0.52	0.91	1.01	0.32	-0.19	0.63	-0.08	0.73	0.50	1.04

HIGH AND LOW FORECASTS

Net LRZ Energy Forecasts (Annual Metered Load in GWh) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	97,574	64,639	48,656	47,074	38,018	93,613	100,800	37,340	113,972	22,230
2019	97,840	64,944	48,106	46,561	37,591	93,120	100,666	37,100	110,951	22,142
2020	98,403	64,963	47,928	46,220	37,272	93,156	98,842	37,327	111,019	22,259
2021	98,591	64,960	48,281	46,081	36,906	93,318	98,308	37,281	110,967	22,443
2022	98,736	65,150	48,358	45,964	36,562	93,727	97,199	37,306	111,149	22,667
2023	99,174	65,277	48,304	45,893	36,271	94,228	95,535	37,387	111,960	22,921
2024	99,892	65,410	48,380	45,797	36,079	94,834	94,812	37,482	112,271	23,170
2025	100,554	65,660	48,720	45,700	35,973	95,397	94,680	37,562	112,627	23,381
2026	101,117	66,049	49,010	45,686	35,970	95,935	94,566	37,598	113,075	23,586
2027	101,564	66,503	49,271	45,707	35,923	96,476	94,405	37,633	113,280	23,806
2028	102,144	67,022	49,537	45,740	35,844	97,003	94,420	37,714	113,855	24,039
2029	102,574	67,634	49,757	45,836	35,785	97,643	94,394	37,878	114,355	24,306
2030	103,032	68,216	50,144	45,930	35,702	98,238	94,530	38,022	115,058	24,599
2031	103,369	68,965	50,567	45,987	35,604	98,902	94,586	38,155	115,698	24,877
2032	103,487	69,646	50,924	46,038	35,480	99,454	94,786	38,286	116,423	25,131
2033	103,656	70,323	51,160	45,955	35,285	100,211	95,016	38,454	117,132	25,395
2034	103,972	71,004	51,458	46,159	35,112	100,808	95,133	38,639	117,833	25,696
2035	104,315	71,653	51,792	46,265	34,981	101,498	95,237	38,855	118,552	25,995
2036	104,730	72,372	52,209	46,414	34,832	102,199	95,465	39,108	119,341	26,307
2037	105,004	73,105	52,676	46,506	34,732	103,033	95,643	39,352	120,248	26,619
2038	105,430	73,872	53,047	46,598	34,622	103,849	95,792	39,618	121,133	26,954
Compound Annual Growth Rates (%)										
2019-2023	0.34	0.13	0.10	-0.36	-0.89	0.30	-1.30	0.19	0.23	0.87
2019-2028	0.48	0.35	0.33	-0.20	-0.53	0.45	-0.71	0.18	0.29	0.92
2019-2038	0.39	0.68	0.52	0.00	-0.43	0.58	-0.26	0.35	0.46	1.04

HIGH AND LOW FORECASTS

Gross Summer Non-Coincident Peak Demand (Metered Load in MW) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,459	12,291	9,285	9,258	7,753	16,244	20,561	7,673	20,713	4,638
2019	17,528	12,398	9,247	9,203	7,677	16,172	20,568	7,658	20,170	4,620
2020	17,651	12,451	9,280	9,182	7,627	16,192	20,230	7,738	20,189	4,645
2021	17,707	12,500	9,399	9,200	7,570	16,233	20,156	7,763	20,187	4,683
2022	17,755	12,585	9,467	9,223	7,520	16,317	19,965	7,802	20,228	4,730
2023	17,856	12,657	9,511	9,254	7,480	16,416	19,662	7,853	20,383	4,783
2024	18,008	12,729	9,580	9,282	7,461	16,533	19,551	7,906	20,447	4,835
2025	18,150	12,823	9,696	9,309	7,458	16,642	19,559	7,956	20,519	4,879
2026	18,274	12,943	9,803	9,340	7,475	16,747	19,570	7,997	20,608	4,921
2027	18,378	13,074	9,905	9,367	7,483	16,852	19,572	8,038	20,654	4,967
2028	18,507	13,217	10,009	9,396	7,484	16,954	19,609	8,088	20,766	5,016
2029	18,608	13,376	10,103	9,435	7,488	17,075	19,638	8,154	20,865	5,072
2030	18,715	13,528	10,229	9,475	7,487	17,188	19,700	8,216	21,001	5,133
2031	18,800	13,686	10,362	9,507	7,483	17,314	19,746	8,276	21,125	5,191
2032	18,847	13,830	10,484	9,538	7,474	17,419	19,823	8,336	21,265	5,244
2033	18,903	13,973	10,584	9,543	7,451	17,560	19,906	8,402	21,403	5,299
2034	18,987	14,118	10,690	9,604	7,433	17,673	19,967	8,472	21,539	5,362
2035	19,075	14,256	10,803	9,646	7,424	17,802	20,027	8,548	21,678	5,424
2036	19,177	14,408	10,932	9,696	7,412	17,932	20,113	8,631	21,830	5,489
2037	19,255	14,562	11,072	9,735	7,410	18,086	20,189	8,712	22,003	5,554
2038	19,359	14,721	11,192	9,773	7,406	18,236	20,259	8,796	22,173	5,624
Compound Annual Growth Rates (%)										
2019-2023	0.46	0.52	0.71	0.14	-0.65	0.37	-1.12	0.63	0.26	0.87
2019-2028	0.61	0.71	0.88	0.23	-0.28	0.53	-0.53	0.61	0.32	0.92
2019-2038	0.52	0.91	1.01	0.32	-0.19	0.63	-0.08	0.73	0.50	1.04

HIGH AND LOW FORECASTS

Gross Winter Non-Coincident Peak Demand (Metered Load in MW) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	14,792	9,470	7,353	7,362	6,501	14,653	14,628	6,391	18,169	3,975
2019	14,851	9,552	7,323	7,319	6,437	14,588	14,633	6,378	17,693	3,960
2020	14,955	9,593	7,349	7,302	6,396	14,606	14,393	6,445	17,710	3,980
2021	15,002	9,631	7,444	7,316	6,348	14,643	14,340	6,466	17,708	4,013
2022	15,043	9,696	7,497	7,334	6,306	14,718	14,204	6,498	17,744	4,053
2023	15,129	9,751	7,532	7,359	6,272	14,808	13,988	6,540	17,880	4,099
2024	15,257	9,807	7,587	7,381	6,256	14,913	13,909	6,585	17,936	4,143
2025	15,377	9,880	7,678	7,403	6,253	15,012	13,915	6,627	17,999	4,181
2026	15,483	9,972	7,763	7,428	6,268	15,106	13,923	6,661	18,078	4,218
2027	15,571	10,073	7,844	7,449	6,275	15,201	13,924	6,695	18,117	4,257
2028	15,680	10,183	7,927	7,472	6,276	15,293	13,951	6,736	18,216	4,299
2029	15,766	10,305	8,001	7,503	6,279	15,403	13,971	6,791	18,303	4,346
2030	15,856	10,423	8,101	7,535	6,278	15,505	14,015	6,843	18,422	4,399
2031	15,929	10,544	8,206	7,560	6,275	15,618	14,048	6,893	18,531	4,449
2032	15,968	10,655	8,303	7,585	6,268	15,713	14,103	6,943	18,654	4,494
2033	16,016	10,766	8,382	7,589	6,248	15,840	14,162	6,998	18,774	4,541
2034	16,087	10,877	8,466	7,637	6,233	15,942	14,206	7,056	18,894	4,595
2035	16,162	10,983	8,555	7,671	6,226	16,058	14,248	7,120	19,016	4,649
2036	16,248	11,100	8,658	7,711	6,215	16,176	14,309	7,189	19,149	4,704
2037	16,314	11,219	8,768	7,742	6,214	16,314	14,363	7,256	19,301	4,760
2038	16,402	11,342	8,863	7,772	6,210	16,449	14,413	7,326	19,450	4,820
Compound Annual Growth Rates (%)										
2019-2023	0.46	0.52	0.71	0.14	-0.65	0.37	-1.12	0.63	0.26	0.87
2019-2028	0.61	0.71	0.88	0.23	-0.28	0.53	-0.53	0.61	0.32	0.92
2019-2038	0.52	0.91	1.01	0.32	-0.19	0.63	-0.08	0.73	0.50	1.04

HIGH AND LOW FORECASTS

Net Summer Non-Coincident Peak Demand (Metered Load in MW) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,428	12,231	9,208	9,212	7,740	16,223	20,525	7,639	20,700	4,638
2019	17,470	12,276	9,091	9,103	7,650	16,133	20,492	7,588	20,150	4,620
2020	17,564	12,268	9,044	9,028	7,582	16,133	20,115	7,634	20,160	4,645
2021	17,591	12,256	9,101	8,992	7,502	16,156	20,001	7,623	20,149	4,683
2022	17,610	12,280	9,105	8,960	7,427	16,222	19,769	7,627	20,180	4,730
2023	17,682	12,292	9,084	8,938	7,363	16,304	19,424	7,642	20,325	4,783
2024	17,804	12,306	9,088	8,910	7,319	16,404	19,271	7,660	20,380	4,835
2025	17,915	12,342	9,143	8,882	7,292	16,497	19,239	7,676	20,442	4,879
2026	18,009	12,404	9,188	8,873	7,287	16,586	19,210	7,682	20,522	4,921
2027	18,082	12,479	9,227	8,874	7,273	16,675	19,171	7,688	20,557	4,967
2028	18,178	12,567	9,267	8,876	7,252	16,762	19,169	7,703	20,659	5,016
2029	18,248	12,672	9,299	8,891	7,236	16,869	19,158	7,735	20,748	5,072
2030	18,323	12,772	9,363	8,906	7,215	16,968	19,180	7,763	20,873	5,133
2031	18,376	12,910	9,433	8,913	7,191	17,079	19,186	7,789	20,987	5,191
2032	18,389	13,035	9,490	8,919	7,161	17,171	19,221	7,815	21,117	5,244
2033	18,412	13,159	9,524	8,899	7,117	17,299	19,262	7,848	21,243	5,299
2034	18,461	13,284	9,572	8,936	7,077	17,398	19,280	7,885	21,368	5,362
2035	18,515	13,403	9,626	8,953	7,045	17,514	19,294	7,928	21,496	5,424
2036	18,581	13,535	9,696	8,978	7,010	17,632	19,334	7,979	21,637	5,489
2037	18,622	13,670	9,776	8,992	6,985	17,773	19,364	8,028	21,800	5,554
2038	18,689	13,810	9,836	9,006	6,957	17,911	19,388	8,080	21,958	5,624
Compound Annual Growth Rates (%)										
2019-2023	0.30	0.03	-0.02	-0.46	-0.95	0.26	-1.33	0.18	0.22	0.87
2019-2028	0.44	0.26	0.21	-0.28	-0.59	0.43	-0.74	0.17	0.28	0.92
2019-2038	0.36	0.62	0.42	-0.06	-0.50	0.55	-0.29	0.33	0.45	1.04

HIGH AND LOW FORECASTS

Net Winter Non-Coincident Peak Demand (Metered Load in MW) —Low

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	14,832	9,421	7,361	7,471	6,575	14,806	14,479	6,435	18,039	3,978
2018	14,762	9,409	7,276	7,316	6,488	14,632	14,592	6,356	18,157	3,975
2019	14,792	9,431	7,167	7,218	6,411	14,548	14,557	6,309	17,673	3,960
2020	14,868	9,410	7,113	7,147	6,350	14,547	14,278	6,341	17,681	3,980
2021	14,887	9,386	7,145	7,108	6,280	14,566	14,184	6,326	17,670	4,013
2022	14,899	9,391	7,135	7,072	6,213	14,624	14,008	6,323	17,696	4,053
2023	14,955	9,387	7,105	7,043	6,155	14,696	13,751	6,330	17,822	4,099
2024	15,053	9,384	7,095	7,010	6,114	14,785	13,630	6,339	17,869	4,143
2025	15,143	9,398	7,126	6,976	6,088	14,867	13,595	6,346	17,922	4,181
2026	15,218	9,433	7,148	6,961	6,080	14,945	13,563	6,345	17,991	4,218
2027	15,275	9,478	7,166	6,956	6,064	15,024	13,524	6,344	18,020	4,257
2028	15,352	9,533	7,185	6,952	6,044	15,101	13,510	6,351	18,109	4,299
2029	15,406	9,602	7,197	6,959	6,027	15,196	13,491	6,372	18,185	4,346
2030	15,464	9,666	7,234	6,966	6,006	15,284	13,495	6,390	18,294	4,399
2031	15,504	9,768	7,277	6,966	5,982	15,383	13,488	6,406	18,393	4,449
2032	15,511	9,860	7,309	6,966	5,954	15,465	13,501	6,422	18,505	4,494
2033	15,525	9,951	7,322	6,945	5,914	15,578	13,518	6,444	18,615	4,541
2034	15,561	10,043	7,348	6,969	5,877	15,667	13,518	6,469	18,723	4,595
2035	15,601	10,131	7,379	6,978	5,847	15,770	13,515	6,500	18,834	4,649
2036	15,652	10,228	7,422	6,993	5,813	15,875	13,531	6,536	18,956	4,704
2037	15,681	10,328	7,472	6,999	5,788	16,001	13,538	6,572	19,098	4,760
2038	15,732	10,431	7,507	7,005	5,761	16,124	13,542	6,610	19,235	4,820
Compound Annual Growth Rates (%)										
2019-2023	0.27	-0.12	-0.22	-0.61	-1.01	0.25	-1.42	0.08	0.21	0.87
2019-2028	0.41	0.12	0.03	-0.42	-0.65	0.42	-0.83	0.07	0.27	0.92
2019-2038	0.32	0.53	0.24	-0.16	-0.56	0.54	-0.38	0.25	0.45	1.04

HIGH AND LOW FORECASTS

Gross and Net MISO System Energy (Annual Metered Load in GWh) —Low

Year	MISO Energy without EE Adjustments	MISO Energy with EE Adjustments
2017	665,862	665,862
2018	665,344	663,915
2019	661,911	659,021
2020	661,779	657,390
2021	662,955	657,136
2022	664,081	656,817
2023	665,666	656,949
2024	668,296	658,127
2025	671,844	660,254
2026	675,537	662,592
2027	678,809	664,568
2028	682,847	667,318
2029	686,952	670,162
2030	691,516	673,470
2031	695,885	676,712
2032	699,964	679,656
2033	704,037	682,586
2034	708,392	685,815
2035	712,861	689,144
2036	717,839	692,977
2037	722,931	696,917
2038	728,048	700,915
Compound Annual Growth Rates (%)		
2019-2023	0.14	-0.08
2019-2028	0.35	0.14
2019-2038	0.50	0.32

HIGH AND LOW FORECASTS

Gross and Net MISO System Coincident Peak Demand (Metered Load in MW) —Low

Year	MISO Summer CP without EE Adjustments	MISO Summer CP with EE Adjustments	MISO Winter CP without EE Adjustments	MISO Winter CP with EE Adjustments
2017	120,779	120,779	99,870	99,870
2018	120,691	120,373	99,760	99,438
2019	120,092	119,448	99,229	98,578
2020	120,035	119,057	99,227	98,240
2021	120,238	118,940	99,405	98,094
2022	120,421	118,800	99,584	97,947
2023	120,670	118,723	99,841	97,876
2024	121,124	118,853	100,245	97,952
2025	121,756	119,167	100,779	98,165
2026	122,416	119,525	101,334	98,415
2027	123,003	119,822	101,826	98,615
2028	123,726	120,258	102,431	98,929
2029	124,465	120,716	103,048	99,263
2030	125,287	121,258	103,731	99,664
2031	126,073	121,794	104,386	100,066
2032	126,810	122,281	104,995	100,420
2033	127,542	122,759	105,602	100,772
2034	128,328	123,295	106,255	101,172
2035	129,132	123,847	106,925	101,587
2036	130,030	124,491	107,671	102,075
2037	130,947	125,153	108,435	102,581
2038	131,867	125,817	109,203	103,091
Compound Annual Growth Rates (%)				
2019-2023	0.12	-0.15	0.15	-0.18
2019-2028	0.33	0.08	0.35	0.04
2019-2038	0.49	0.27	0.51	0.24