DATA REQUEST

KPSC 2_1 Refer to the Direct Testimony of Lerah M. Kahn (Kahn Direct Testimony), page 7, Table LMK-2, and Kentucky Power's response to Commission Staff's First Request for Information (Staff's First Request), Item 33.

a. Provide the individual load forecast, including supporting assumptions, broken out by customer class including Residential, Commercial, Industrial, Other Retail, and FERC Municipals forming the basis for the projected kWh sales.

b. Provide Kentucky Power's most recent 15-year forecast for number of customers using the same breakout as requested in part a. above.

RESPONSE

a. and b. Please see KPCO_R_KPSC_2_1_Attachment1 for the requested information. Notably, the sales in Table LMK-2 represent sales based on the Company's generation, off system sales, purchases, and system losses consistent with the denominator calculation for the Fuel Adjustment Clause (Page 3 of 5).

The slight variation in total sales between Table LMK-2 and KPCO_R_KPSC_2_1_Attachment1 arise from a variation in the manner in which the forecasts by generation source and by customer class are derived. The difference is within rounding range of each other.

Witness: Lerah M. Kahn

Total Energy Uses (GWh)	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Residential	1878	1870	1856	1839	1823	1813	1793	1789	1780	1773
Commercial	1151	1148	1144	1141	1136	1134	1127	1123	1123	1122
Commercial #2 (Data Centers)	272	273	273	273	273	273	273	273	273	273
Industrial	1944	1940	1937	1933	1926	1918	1910	1901	1893	1887
Other Retail	9	9	8	8	8	8	8	8	8	8
Subtotal	5255	5240	5219	5194	5166	5147	5112	5095	5077	5065
Losses and Company Uses	402	395	395	391	388	387	386	382	382	381
Total Energy Uses (GWh)	5656.458	5634.776	5613.172	5584.861	5554.807	5533.628	5497.983	5477.202	5459.658	5445.490

Customers	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Residential	130,004	129,497	128,969	128,423	127,868	127,310	126,756	126,203	125,647	125,081	124,507	123,922	123,326	122,717	122,096
Commercial	30,328	30,305	30,281	30,259	30,237	30,215	30,194	30,174	30,153	30,132	30,111	30,090	30,069	30,049	30,029
Commercial #2 (Data Centers)	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial	922	913	903	894	885	876	867	858	850	841	832	824	816	807	799
Other Retail	299	299	299	299	299	299	299	299	299	299	299	299	299	299	299
Total Customers	161,555	161,016	160,456	159,878	159,291	158,703	158,119	157,537	156,951	156,356	155,752	155,138	154,513	153,875	153,226

DATA REQUEST

KPSC 2_2 Refer to the Direct Testimony of Clinton M. Stutler (Stutler Direct Testimony), page 14, line 23, and page 15, lines 1-6. Describe whether the explanation of Kentucky Power's energy hedging program means that Kentucky Power secures forward contracts up to 36 months in advance.

RESPONSE

Pursuant to the energy hedging program, Kentucky Power "may" pursue fixed price, physical fuel purchases up to 36 months in advance of anticipated use.

At the 36-month milestone, Kentucky Power targets a hedge percentage of 33 percent of its forecasted weather-normalized customer load. Therefore, 36 months prior to anticipated use, Kentucky Power will review and compare available resources to determine the lowest cost alternative to hedge customer load. For example, if the Mitchell Plant is available, and coal is the least cost alternative to hedge customer load, coal purchases will be pursued. Alternatively, if the Big Sandy Plant is available, and natural gas is the least cost alternative to hedge customer load, natural gas purchases will be pursued.

As time progresses, larger percentages of weather-normalized customer load is hedged through fixed price, physical coal and natural gas purchases.

Witness: Clinton M. Stutler

DATA REQUEST

KPSC 2_3 Refer to the Stutler Direct Testimony, page 17.

a. Confirm that according to Kentucky Power's maintenance schedule, for the Big Sandy plant's planned outages, no forward gas contracts are or were purchased. If not confirmed, explain how the planned maintenance schedule is accommodated with the forward purchases.

b. Provide a table showing Kentucky Power's daily Operating Balancing Account (OBA) over the review period and when Kentucky Power was required to sell or purchase natural gas to keep its OBA within Columbia Gas Transmission limits.

RESPONSE

a. Not confirmed. The planned maintenance schedule for the Big Sandy Plant is considered when determining appropriate purchase quantities of forward month, fixed price natural gas supply.

For example, if there is a planned outage that spans for more than 50 percent of the days in the month, then no forward month natural gas supply is purchased for that particular month. However, if the planned outage spans for less than 50 percent of the days in the month, natural gas supply may be purchased, but at a lower daily quantity, as the natural gas supply will need to be carried on the OBA, or sold back into the market (for the days that the Big Sandy Plant is in outage).

b. Please see KPCO_R_KPSC_2_3_Attachment1 for the requested information.

Witness: Clinton M. Stutler

DATA REQUEST

KPSC 2_4 Refer to the Direct Testimony of Jason M. Stegall (Stegall Direct Testimony), page 4, lines 15-22. If the Big Sandy or Mitchell units are in Reserve Shutdown, explain the notice time PJM Interconnection, LLC (PJM) provides if the units need to be online.

RESPONSE

PJM provides a minimum of one hour notice for a unit to begin its startup process. A unit's startup time is based on the state of the unit at the time of startup and is classified as hot, warm, or cold. Each unit would be able to start in an amount of time equal to the PJM startup notification time (e.g., one hour) plus the startup time required for its current state: hot startup time, warm startup time, or cold startup time.

Witness: Jason M. Stegall

DATA REQUEST

KPSC 2_5 Refer to the Stegall Direct Testimony, page 12, lines 17-18. Explain why Kentucky Power would pay for coal it could not receive.

RESPONSE

The Company's coal contracts include an obligation to accept and pay for coal in accordance with a delivery schedule arranged with the supplier. If the Company is not able to accept delivery pursuant to the contract's delivery schedule and the Company cannot address this contractual issue through the methods described in the Company's response to KPSC 2-7(b), the Company will be subject to damages as set forth in the contract.

Witness: Jason M. Stegall

Kentucky Power Company
KPSC Case No. 2025-00338
Commission Staff's Second Set of Data Requests
Dated February 6, 2026

DATA REQUEST

KPSC 2_6 Refer to the Stegall Direct Testimony, page 16. Explain whether the generation unit status of Kentucky Power's regulated affiliates affects the decision to place one of Kentucky Power's units into Reserve Shutdown or affects the timing and duration of the shutdown.

RESPONSE

Reserve shutdowns occur when the Company offers a unit into the PJM market for economic dispatch and PJM does not select the unit to commit and dispatch energy into its energy markets. The status of Kentucky Power's regulated affiliates' generating units have no bearing on whether a particular Kentucky Power unit is placed in reserve shutdown.

Witness: Jason M. Stegall

DATA REQUEST

KPSC 2_7 Refer to Kentucky Power's response to Staff's First Request, Item 3.

a. Explain why Kentucky Power allowed its coal inventory levels to grow to significant levels above target.

b. Explain the actions, if any, that Kentucky Power took to manage its receipt of coal and the coal inventory levels. Include in the response the current estimated high sulfur and low sulfur inventory levels.

c. Explain why it is a prudent strategy for Kentucky Power to commit significant amounts of capital in coal inventory that cannot be recovered until the coal is consumed.

d. Provide the estimated value of the low sulfur coal contained in inventory represented by the difference between the target level and 97 days above target.

RESPONSE

a. There are a myriad of factors that led to the coal inventory levels set forth in the Company's response to Staff First Request, Item 3. Most notably, as discussed in direct testimony of Company Witness Chilcote on pages 6 and 7, Kentucky Power procures coal based on a forecast at the time of the purchase and layers in purchases over time. Much of the purchasing decisions for 2023 and 2024 were made in previous years such as 2021 and 2022. In those two years, the coal market was experiencing unprecedented scarcity due to a projected increase in coal fired generation. This was caused by elevated natural gas prices, which influenced the forward market for coal. However, the projected increase in coal fired generation did not materialize due to a drop in natural gas prices, which then resulted in lower coal consumption. On page 9 of his direct testimony, Company Witness Stegall discusses how the sudden drop of natural gas prices impacted the energy market, which ultimately impacted coal fired generation. Kentucky Power then had to find the most reasonable solutions to actively managing the inventory at the plant to maintain safe inventory levels, which are further discussed in the response to sub-section (b).

b. Kentucky Power reviewed multiple options to manage inventory levels during 2023 and 2024. This included but was not limited to working with suppliers throughout 2023 and 2024 to modify contractual obligations. In 2023, Kentucky Power worked with five suppliers to cancel or defer 2023 obligations. Kentucky Power also mutually terminated one agreement in 2023. Kentucky Power was able to defer 517,000 tons and cancel 176,300 tons from its 2023 obligations. In 2024, Kentucky Power again worked with two suppliers to defer 386,000 tons to later years. As of December 31, 2025, Kentucky Power had 280,405 tons of high sulfur (or 51 days of full load burn – Kentucky Power Share) and 220,857 tons (or 84 days of full load burn – Kentucky Power share) of low sulfur coal in inventory.

c. Please see the Company's response to sub-part (a) for an explanation of the coal inventory levels of 2023 and 2024. Additionally, when determining how to manage its inventory to safe levels, the Company assesses options which include but are not limited to paying a fee to reduce the volume, deferring tons to a future year, eliminating tons with no payment, selling tons, using off-site storage of tons, or maximizing existing storage piles to safe inventory levels. The Company executes their decision based on the least cost alternative with the information available at the time the decision is made. Kentucky Power utilized a number of the aforementioned options to pursue the least cost alternatives and the best solutions for customers, including but not limited to utilizing the available storage capacity and working with coal suppliers to avoid paying damages to the suppliers as further discussed in the Company's response to sub-part (b). Kentucky Power continues to work to bring the coal pile inventory to the target levels.

d. Please see the table below for the Kentucky Power share of the value of the low coal sulfur pile as of October 31, 2024, at the (i) inventory level (132 days), (ii) difference between the 35 day target level and 97 days above target (97-35=62 days), and (iii) target level (35 days).

Low Coal sulfur pile value as of October 31, 2025 (Full Load Burn) at:	**Amount $**
(i) Inventory level (132 days)	$43,217,656.33
(ii) Difference between 97 days above target and 35 day target level (62 days)	$20,382,011.55
(iii) Target level (35 days)	$11,417,822.39

Witness: Kimberly K. Chilcote

DATA REQUEST

KPSC 2_8 Refer to Kentucky Power's response to Staff's First Request, Item 5. Explain whether the contract purchases listed in Attachment 1 were forward purchases.

RESPONSE

For purposes of this response, the Company understands the reference to Item 5 to instead be Item 2 and "forward purchases" to mean purchases made in years prior to the contract's delivery year. Accordingly, yes, the agreements listed in Staff's First Request, Item 2 are forward purchases.

Witness: Kimberly K. Chilcote

Kentucky Power Company
KPSC Case No. 2025-00338
Commission Staff's Second Set of Data Requests
Dated February 6, 2026

DATA REQUEST

KPSC 2_9 Refer to Kentucky Power's response to Staff's First Request, Item 8.

a. Provide the number of years Kentucky Power uses to weather normalize its data.

b. Explain whether Kentucky Power has conducted a study varying the number of years used in its weather normalization calculations to capture increasing weather variability. If so, provide the results of that study.

RESPONSE

a. Currently, Kentucky Power uses a 20-year normal. Prior to 2025, Kentucky Power used a 30-year normal.

b. Kentucky Power switched to a 20-year normal in January 2025, a result of a comprehensive weather study conducted during the first half of 2024. The study included extensive historical weather data and sales analysis, peer review of industry studies and consultations with meteorologists. Please see KPCO_R_KPSC_2_9_Attachment1 for the study.

Witness: Jason M. Stegall

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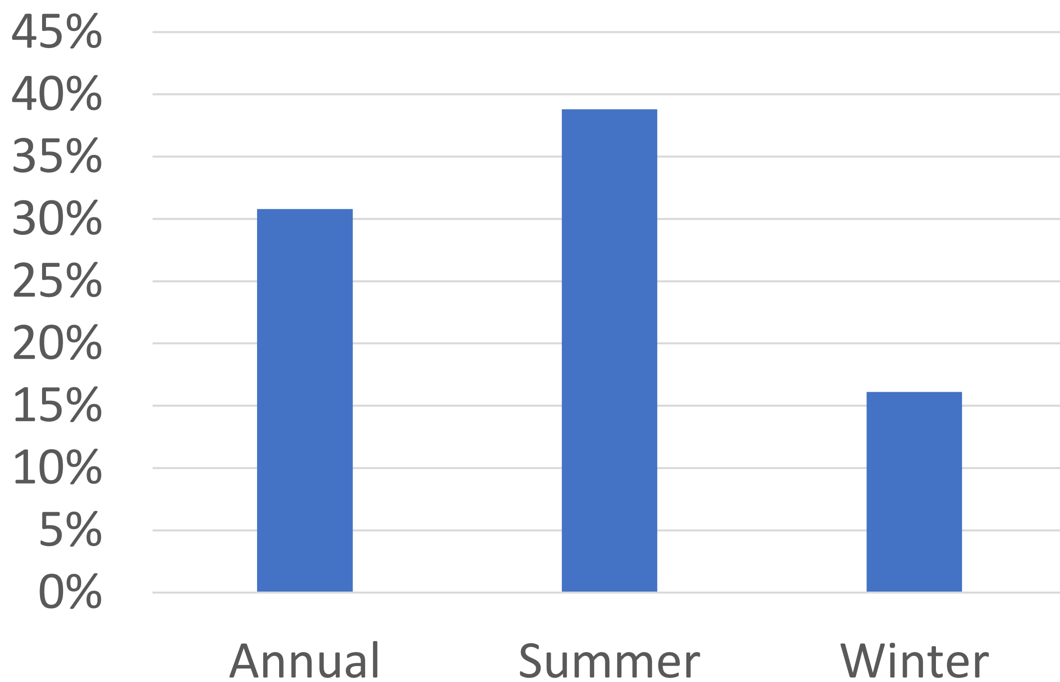
Introduction

In an era marked by changing weather, the electric utility industry faces significant challenges in accurately forecasting energy consumption. Weather has always been a crucial factor influencing energy usage, and understanding its impact is essential for effective load forecasting and reporting. While economic conditions and customer behavior play important roles, it is the variability of weather that often leads to the most pronounced fluctuations in energy demand. In fact, American Electric Power's (AEP) internal analysis shows that as much as 40% of electricity sales in the residential and commercial classes can be from weather alone (see Figure 1).



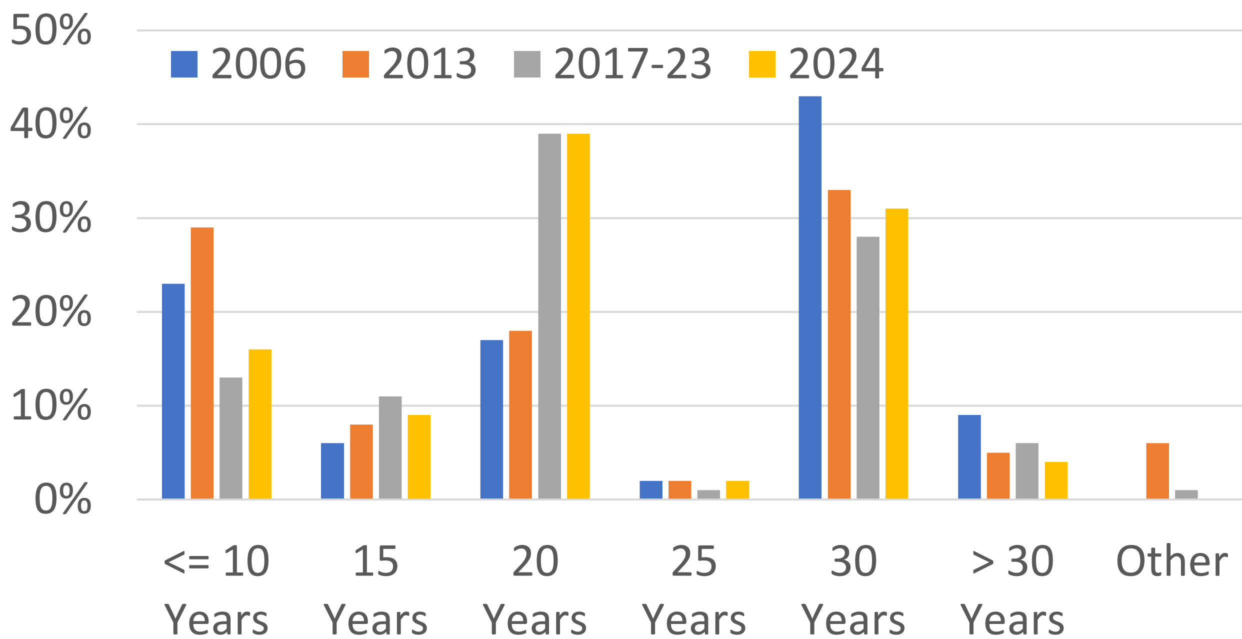
2013-2022 Average. Summer = Jun.-Sept.; Winter = Dec.-Feb.

Figure 1: Share of Residential Energy Associated with Weather at an AEP Operating Company

Given the importance of weather in influencing energy usage, it is imperative that AEP use the best representation of weather to forecast energy usage and normalize sales (Elkhafif). This is especially important in regulatory settings as both forecast and historical sales are used to set rates. If an insufficient representation of weather is used to either forecast or adjust sales, that can lead to rates being set too high or too low. Neither are good for our customers as too low of rates necessitates additional rate case filings to assure recovery of costs. It's thus critical to ensure that AEP uses the most appropriate definition of weather. This process is known as weather normalization and relies on developing the best definition of normal weather. This typically refers to average weather conditions, such as temperature, over a specific period, that can be used as a baseline to understand typical weather patterns.

As weather patterns have evolved, AEP must navigate the complexities of an evolving climate landscape to ensure we maintain forecast accuracy and therefore produce accurate resource plans, financial plans, and regulatory filings. Traditional approaches, including the 30-year Standard Climate

Normal (SCN), have served as the benchmark for defining normal weather patterns (Livezey, et. Al.). This has been the approach that AEP has followed to date, with the addition of rolling the 30-year period forward each year. According to Itron's annual benchmark survey[1], utilities have been moving away from the traditional 30-year approach and toward shorter periods, with the 20-year period being the most common amongst over 100 utilities surveyed (see Figure 2).



Data source: Itron 2024 Forecast Accuracy Benchmarking Survey

Figure 2: Share of Utilities Using Given Weather Normalization Periods

One of the primary reasons for this shift is that as climate change accelerates, it is becoming increasingly clear that this historical standard may no longer provide the relevant insights needed to inform load forecasting (McMenamin). Recent extreme weather events—such as hurricanes, heatwaves, and general temperature shifts—underscore the limitations of relying solely on outdated data for forecasting. As can be seen in figure 3, not only are average temperatures increasing over time in the US, but the volatility is also accelerating. This is also true for the AEP territory, which has experienced declining heating degree days (HDD) and increasing cooling degree days (CDD) since 1970. Moreover, we have also experienced rapid swings in degree days from year to year, further highlighting the volatility and increased challenges of normalizing weather in a changing climate. These are illustrated in figure 4 below.

[1] 2024 Forecast Accuracy Benchmarking Survey and Energy Trends; Itron.

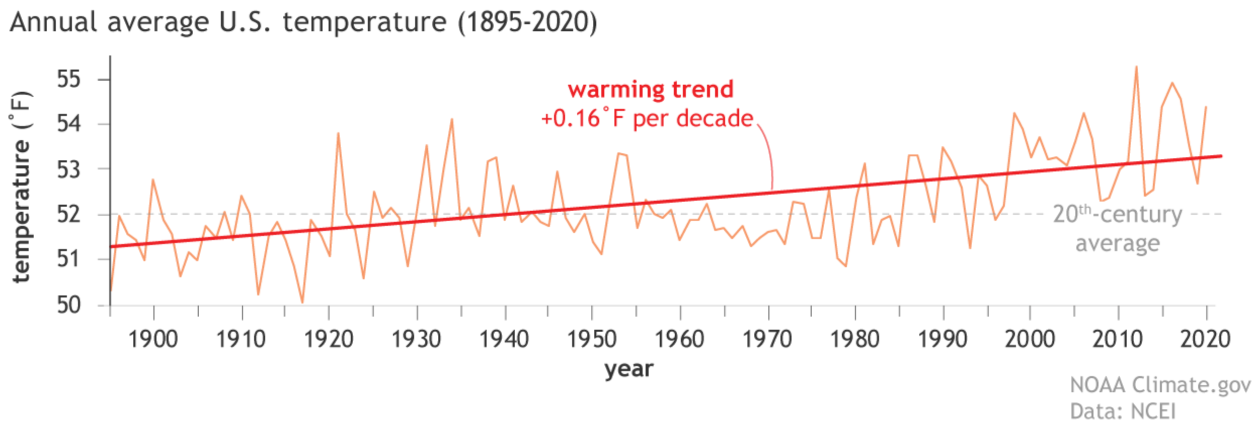


Figure 3: Annual Temperature Trends

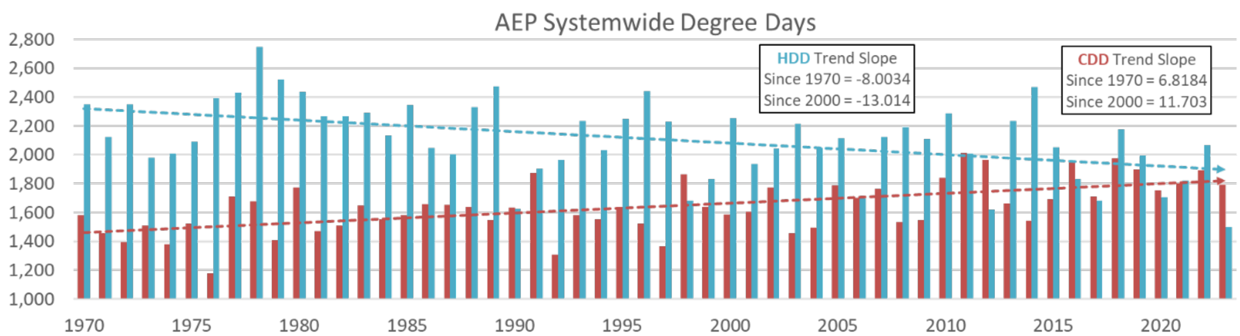


Figure 4: AEP Degree Days Since 1970

To better align our forecasts and weather adjustments with current climate realities, AEP's Economic Forecasting team undertook a comprehensive study in the summer of 2024 to evaluate the most appropriate definition of normal weather for the AEP service territory. This study led to the conclusion that a 20-year normal with hourly averages was the most accurate and representative for AEP. This study not only allowed us to enhance our understanding of energy consumption patterns, but it also displayed the need to adapt to the challenges presented by a changing climate. By utilizing a 20-year normal, AEP can capture more recent trends and variations, enabling us to make informed decisions that directly impact resource planning and financial performance.

In addition to moving from a 30-year normal to a 20-year normal, we also assessed how the common measure of weather, degree days, is calculated. As we want to ensure we are accurately capturing how our customers respond to weather, it was necessary to also evaluate this calculation. Ultimately, we found that relying on two measures of temperature, the daily minimum and maximum, was missing nuances in how customers and their corresponding cooling and heating equipment respond to weather. As such, in addition to shortening the periodicity, we also determined using an average of all 24 hours in a day would lead to increased accuracy in our load forecasting, planning, and regulatory filings.

This paper outlines how AEP assessed weather normalization and degree day calculation options so that we ensure our definition of normal weather reflects the changing climate and supports AEP's commitment to maintaining forecasting accuracy so planning and regulatory filings are also accurate. By examining how we decided to move forth with a 20-year normal with hourly averages, we aim to provide a clear perspective on how this transition can strengthen AEP's forecasts, ultimately ensuring that we meet the evolving needs of our customers and stakeholders. As we delve deeper into this critical issue, we will explore the rationale behind this proposed change and its potential benefits, setting the stage for a more resilient and responsive approach to load forecasting.

Defining Normal Weather

In meteorology, "normal" refers to the long-term average of weather parameters for a specific region over a defined period, with temperature being a primary focus in the utility industry. Understanding normal weather is essential for effective energy forecasting and is closely linked to the calculation of degree days—a comprehensive metric that can be used to quantify how ambient temperature affects energy consumption for heating and cooling. Degree days combine temperature (measured in degrees) with duration (measured in days, months, or years) to assess energy needs associated with weather variations. Averaging these over a number of years leads to a definition of normal weather, or the number of degree days one can reasonably expect in a given year.

Specifically, Cooling Degree Days (CDD) measure the number of days when outdoor temperatures exceed 65°F, indicating the demand for cooling, while Heating Degree Days (HDD) quantify the number of days when temperatures fall below 55°F, signaling the need for heating. Temperatures between 55 and 65 degrees are considered base load, where neither heating nor cooling load is prevalent. This is evidenced in figure 4 below which show a clear relationship in energy usage as temperatures drop below or rise above the threshold.

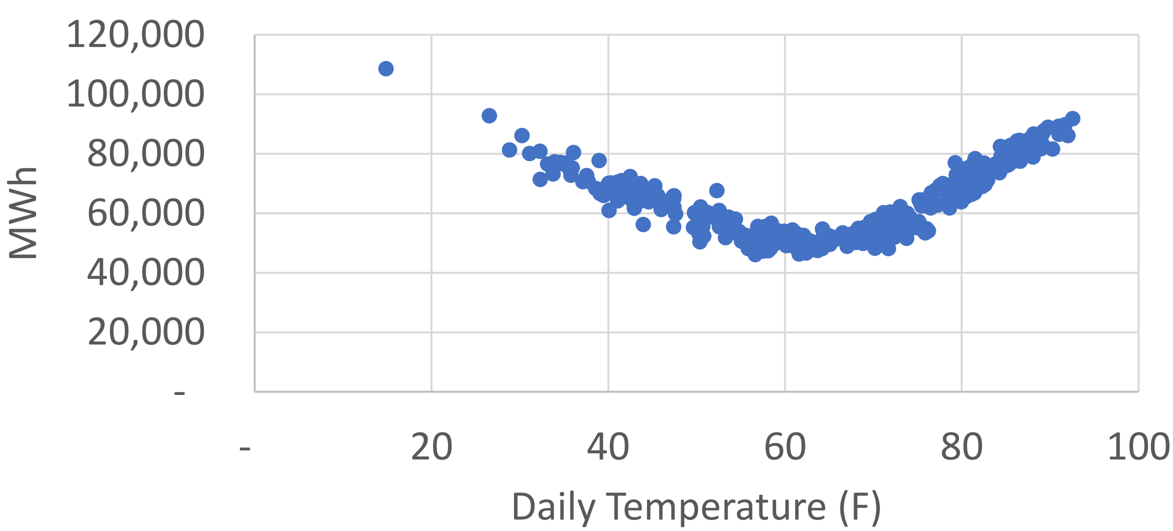


Figure 5: Energy and Temperature Relationship for Sample AEP OPCo

The most common approach, as illustrated in equation 1, to calculating degree days is by taking the average of the daily minimum and maximum temperature. This topic will be revisited later. The primary focus for now is on the periodicity of weather normal.

Equation 1: Traditional Method for Calculating Degree Days

$$CDD = max(average(Daily\ Min., Daily\ Max) - 65\ degrees, 0)$$

$$HDD = max(55\ degrees - average(Daily\ Min., Daily\ Max), 0)$$

Traditionally, a 30-year timeframe has been used to establish these averages, providing a solid foundation for understanding typical weather patterns. However, as we experience climate change, this historical standard is increasingly being challenged as the longer period may not reflect current climate realities. The rationale for a 30-year normal lies in its ability to smooth out short-term variations and provide a comprehensive view of long-term climate trends. The World Meteorological Organization (WMO) endorses[2] this practice, asserting that 30 years is a sufficient period for capturing the variations in climate that occur over time. However, the rapid pace of climate change has led to significant shifts in weather patterns, making it essential to reassess what constitutes normal.

Weather normals should also capture various climate cycles and phenomena that influence weather patterns, else they run the risk of being biased towards a narrow set of climatological conditions. For instance, these periods encompass the effects of El Niño and La Niña events[3], which can cause substantial fluctuations in temperature and precipitation across different regions. El Niño, characterized by warmer ocean temperatures in the Pacific, often leads to wetter conditions in some areas and droughts in others, while La Niña typically results in the opposite effects.

In addition to these oceanic cycles, longer normalization periods can also account for solar cycles, including sunspot activity, which has been shown to correlate with changes in climate patterns. Sunspots can influence solar radiation and, consequently, climate over extended periods. These cycles typically last about 11 years on average. However, the length of these cycles can vary, ranging from 9 to 14 years[4]. By incorporating these cycles, a longer weather normalization period can provide a comprehensive view of how various factors interact to shape climate and weather patterns.

However, while longer periods capture these critical climate cycles, it is essential to recognize that they may also reflect outdated conditions that do not account for the changes occurring due to climate change. Therefore, balancing the insights gained from longer periods with more recent data is crucial for accurate forecasting.

[2] World Meteorological Organization. (2011). Guidelines on climate normals and climate variability. https://www.wmo.int/pages/prog/wcp/wcasp/documents/WMO_1100_en.pdf
[3] NOAA. What are El Nino and La Nina?. Retrieved from NOAA.gov
[4] NASA. (2021). "Solar Cycle 25: The Next Solar Cycle." Retrieved from NASA Solar Dynamics Observatory.

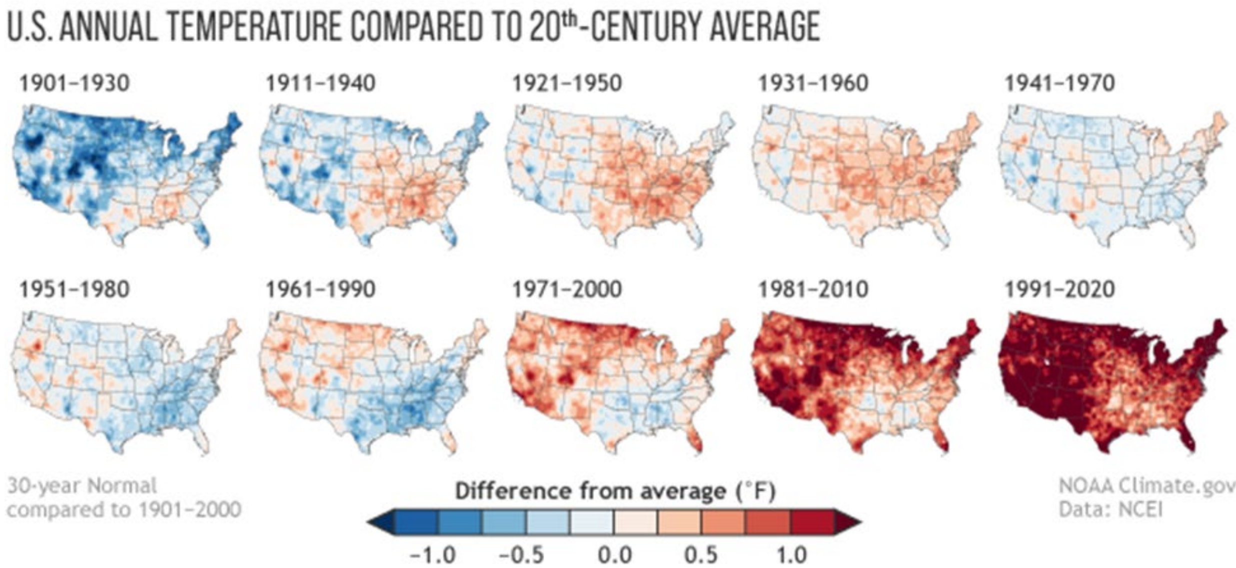


Figure 6: US Annual Temperatures vs. 20th Century Average

Recent studies indicate a notable warming trend, particularly in minimum temperatures across the United States. Research by the National Oceanic and Atmospheric Administration (NOAA) shows that average temperatures have increased by approximately 1.8°F since the late 19th century[5], with more pronounced changes observed in recent decades. This trend significantly impacts energy consumption patterns, with more frequent extreme temperatures directly correlating to differing energy demands than in the past. AEP must adapt to these changes to effectively manage resources and ensure accurate planning and regulatory filings.

For instance, a study conducted in 2019 revealed a dramatic increase in the number of days exceeding 90°F in many regions over the past 30 years (Dahl). Relying on 30 years of data to develop forecasts increases the potential for this type of data to be underweighted. The case for transitioning to a shorter time frame becomes stronger when considering the implications of outdated data on forecasting accuracy (McMenamin). Reliance on a 30-year normal may lead to significant discrepancies between forecasted and actual energy consumption, particularly during peak demand periods. This is apparent in figure 6 where the 30-year normal period used by NOAA have evolved rapidly from the 20th century average with each update. For example, using any 30-year period since at least 1990 through 2020 would have missed a significant amount of warming.

As mentioned in the introduction, many utilities are now shifting away from the 30-year normal as a result. The 2024 annual Itron survey shows that many utilities are converging on using a 20-year normal as well. By also adopting a 20-year normal, AEP can better reflect current weather patterns and provide more accurate forecasts. This strategic shift to adopt a shorter period not only enhances forecasting accuracy but also positions AEP to better serve its customers in a changing climate.

[5] National Oceanic and Atmospheric Administration (NOAA). (2021). "Climate Change: Global Temperature." Retrieved from NOAA Climate.gov.

Evaluating Time Periods

To evaluate the effectiveness of different normalization periods, AEP conducted a comprehensive analysis of historical weather data. The objective was to determine whether the current 30-year normal remains appropriate or if a shorter period would provide a more accurate reflection of recent climate trends. Periods ranging from 10 to 30 years in five-year increments were assessed on a rolling basis, with an emphasis on identifying the optimal normalization period for the entire AEP system. Given the geographic diversity of AEP, stretching from Virginia to Texas, it was important to assess each period on its effectiveness for both HDD and CDD. Accordingly, while both were evaluated independently it was imperative to that the final assessment balanced HDD and CDD equally.

To determine the effectiveness of each normalization period, we evaluated several key metrics. Metrics were focused on being representative of historical data, being accurate for forecasting, and volatility. Before evaluating each normalization period, a t-test was performed to compare normalized actuals against non-normalized actuals. This statistical test assesses whether the differences between the two are significant, ensuring that the chosen normalization period accurately represents actual weather conditions. During the study we found that each period was not statistically different from the actuals, thus each period passed the t-test as we did not want the chosen period to be statistically different from actuals. Like our desire to capture a balance between heating and cooling, we also sought balance on the four metrics used. This was to help assure the period chosen was accurate, did not exhibit significant volatility, and was reflective of recent weather trends. The metrics used to evaluate the weather normalization periods are detailed in Table 1 below, providing a comprehensive overview of the criteria applied in our analysis.

Table 1: Metrics Used to Evaluate Weather Normal Periods

Average Temperature	The average temperature calculated over the normalization period helps gauge typical conditions. This metric is vital in understanding the baseline for energy consumption and can reveal shifts in climate.
Volatility (Standard Deviation)	This measures how much temperature varies over the normalization period. A lower standard deviation suggests more stable conditions. Volatility can significantly impact energy demand forecasts, as more extreme temperature variations often lead to unpredictable spikes/drops in energy use.
Variance from Actuals	This metric indicates how much normalized temperatures differ from actual recorded temperatures. A smaller difference signifies better accuracy in forecasting. By comparing the variance, AEP can identify which normalization period provides the most reliable predictions for energy consumption.
Trend	This shows whether temperatures are increasing or decreasing over time, with a steeper slope indicating significant changes in weather patterns. Understanding the trend is essential for anticipating future energy demands, as it can reveal long-term shifts in climate that affect seasonal consumption patterns.

After calculating these metrics, we weighted each of the four metrics equally and compared results for each across the different normalization periods. We then indexed each metric and created a composite index of all four to determine the best periodicity of normal for AEP. A lower index value was preferable, and the results of the composite index for both HDD and CDD is in table 2.

Table 2: Comparison of Weather Normal Periods

Overall Composite Index (lower = better)

	10-year	15-year	20-year	25-year	30-year
AEP-Total	77.4%	73.4%	73.3%	89.4%	92.1%

This analysis further revealed that a shorter normalization period would yield more accurate forecasts overall, as they captured recent warming trends more effectively. That revealed that AEP could have better anticipated fluctuations in energy demand, allowing for more effective planning and rate making. The trade off with using less than 30 years was a general increase in volatility. This was particularly apparent in the 10- and 15-year normal periods. This can be seen below in figure 7 with the up-and-down nature of normal in 2002 and 2008 for the 10-year, and 2007 for the 15-year, for example. This was a negative mark against them as it is undesirable to have large swings from year to year in the definition of normal, as that could cause large fluctuations when setting customer rates. Volatility metrics for the 20-year were often similar to the 30-year, and in the case of HDD were actually lower.

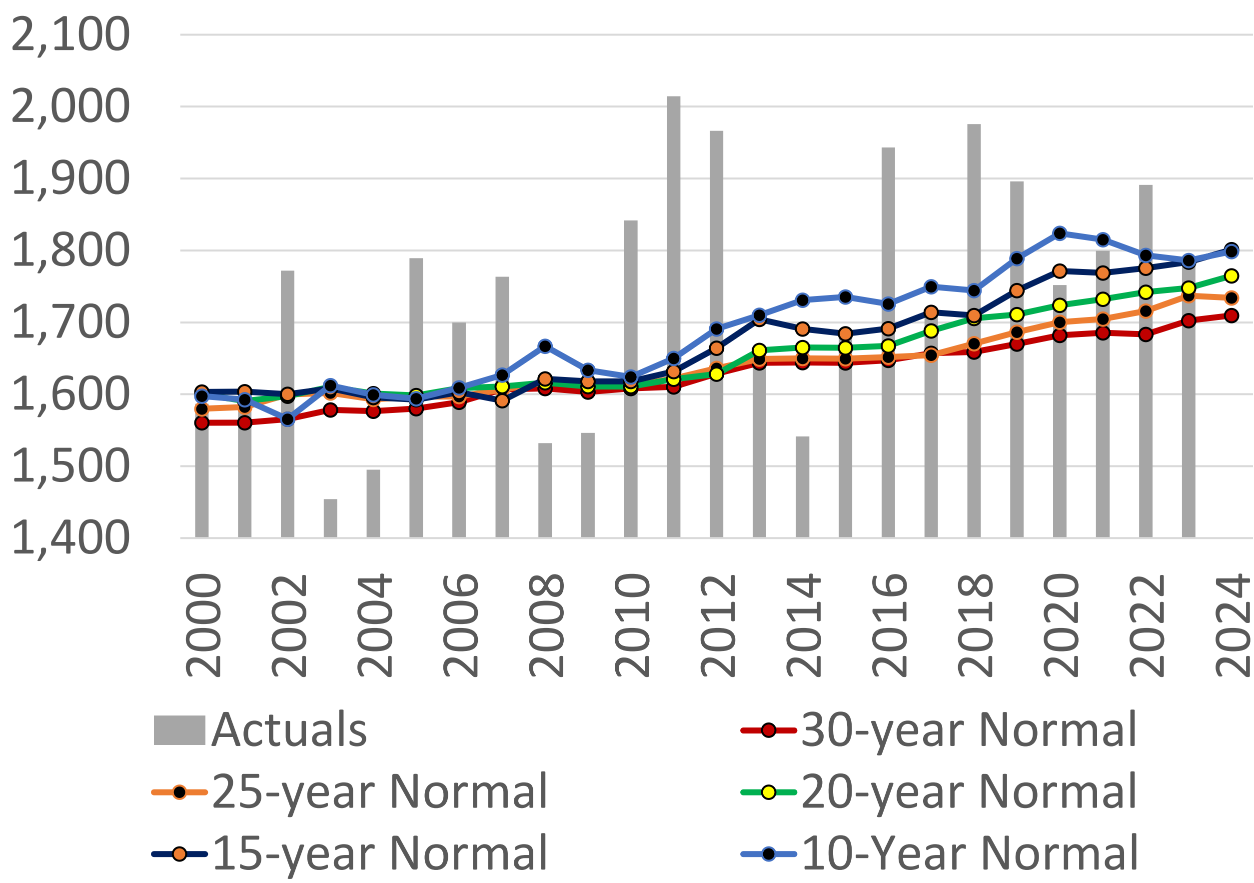


Figure 7: Normalization Periods Considered, AEP Systemwide CDD

Our analysis found that the 20-year normal struck a balance between accuracy and volatility, generally outperforming the 30-year normal across most metrics for both HDD and CDD. This was particularly true in terms of variance from actual temperatures and average temperature alignment. A normalization period with a lower variance from actuals and a more stable average temperature is preferable, as it indicates improved forecasting accuracy. These factors, along with being long enough to capture multiple climate cycles referenced earlier, led us to adopt the 20-year normal as our new definition of weather normal moving forward. Given AEP's diverse geographic footprint and the increasing unpredictability of weather patterns, adopting a 20-year normal would not only facilitate more accurate forecasting but also align AEP's regulatory filings with the realities of a changing climate, ultimately benefiting both AEP and its customers.

How We Calculate Degree Days

As previously mentioned, degree days have typically been computed by taking the average of the daily minimum and maximum temperatures (min/max) and comparing them to a baseline (see Equation 1). Using daily minimum and maximum temperatures has largely been used for two reasons: simplicity and the availability of hourly data over a long enough period of time. With advancements in weather data collection and analysis, it is now possible to utilize daily average temperatures across all 24 hours instead, particularly when using a shorter 20-year normal. During this study, we also evaluated the merits of switching to this approach. We found that this approach allows for a more nuanced and accurate view of how temperature fluctuations throughout the day impact energy consumption.

Customers' heating and cooling loads do not simply respond to extreme daily minimum and maximum temperatures; rather, they react dynamically to changes in temperature throughout the entire day. For instance, air conditioning systems are not constantly running at full capacity; instead, they cycle on and off based on the ambient temperature. On a very hot day, an AC compressor might run hard for extended periods, particularly during peak afternoon hours when temperatures are highest, leading to increased energy consumption. Conversely, during cooler times of the day or night, the system may cycle off, resulting in less energy being consumed.

This dynamic response is not limited to cooling loads alone. Heating systems also exhibit similar behavior; for example, during mild winter days, a heating system may operate intermittently, only activating when temperatures fall below a certain threshold. Additionally, other weather-sensitive loads adjust their operation based on temperature fluctuations as well.

Adopting the use of a 24-hour daily average temperature in our degree day calculations will allow AEP to capture these subtle nuances in customer behavior and appliance cycling. For example, a day with an hourly average temperature of 80°F may lead to a different load profile than a day with a high of 90°F and a low of 70°F, even if the extremes are the same. By focusing on daily averages, we can better account for the actual cooling demand driven by customers' responses to temperature changes throughout the day.

This is best illustrated with the example shown in figure 7, which compares the traditional method of averaging the daily minimum and maximum temperature (labeled current state) versus averaging over all 24 hours of the day (labeled future state). These temperatures represent actual temperatures experienced on a winter day at one of AEP's operating companies. Even though they are trying to depict the same concept (how cold a day was on average), there is a 2.6-degree difference between the two. In this case, the traditional min/max approach skews towards the max reading, despite only six hours of the day being at or above the 37-degree average. Meanwhile, the hourly average more closely represents what was experienced through most of the day, averaging 34.4 degrees. As such, in this example, since colder weather generally corresponds to more energy usage, the traditional min/max would have understated the amount of energy associated with weather.

Although this is only one day and a relatively small difference, research (Yao) has shown that small changes in average temperature can lead to disproportionately large variations in energy demand. Further, industry leading consultant Itron has also noted increases in forecasting accuracy by moving to

24-hour averages[6]. By employing a refined methodology that leverages daily average temperatures, AEP can better capture these small changes and achieve more accurate load forecasting.

Example:

					Min Temp									Max Temp									
Hr1	Hr2	Hr3	Hr4	Hr5	**Hr6**	Hr7	Hr8	Hr9	Hr10	Hr11	Hr12	Hr13	Hr14	**Hr15**	Hr16	Hr17	Hr18	Hr19	Hr20	Hr21	Hr22	Hr23	Hr24
32.6	32.0	31.7	31.2	31.1	**30.9**	31.3	31.9	33.4	34.1	36.2	38.4	40.9	42.4	**43.1**	42.0	37.6	35.4	33.2	31.8	31.5	31.1	31.1	31.0

Current State

Avg Temp = (30.9 + 43.1) / 2 = 37.0

HDD = (55.0 – 37.0) = 18

18 HDD

Future State

Avg Temp = (825.9 / 24) = 34.4

HDD = (55.0 – 34.4) = 20.6

20.6 HDD

Figure 8: Calculating Degree Days, Daily Min/Max Average vs. Hourly Average

[6] Itron(2014). Using the Right Weather Data. Retrieved from Itron website.

Conclusion

This review of weather normalization at AEP represents a continuous improvement process critical to AEP's load forecast and therefore planning and regulatory efforts. The transition to a 20-year normal is not merely a response to changing circumstances; it is a strategic imperative that will empower AEP to thrive in an evolving energy landscape. By adopting this approach, AEP can better align its forecasting with contemporary conditions, ultimately leading to more accurate resource, financial, and regulatory plans.

Furthermore, by adopting a 20-year normal, AEP can enhance its resilience against climate volatility. As severe weather events become more frequent, the ability to accurately forecast energy demands will be critical in ensuring that AEP can meet the needs and demands of its stakeholders. Ultimately, this proactive shift to a 20-year normal not only enhances AEP's forecasting capabilities but also positions the utility to address the evolving needs of its customers amidst a rapidly changing climate. By embracing a forward-thinking approach, AEP can ensure its operations remain resilient and responsive, fostering trust and satisfaction among its stakeholders. We encourage all stakeholders of AEP to actively support this transition to a 20-year normal. By collaboratively embracing these changes, we can better equip ourselves to meet the challenges posed by climate variability while ensuring a sustainable and reliable energy future for our customers.

References

Dahl, K. A. "The Impact of Climate Change on Extreme Heat Events in the United States." Environmental Research Letters, vol. 14, no. 10, 2019, p. 104008. https://doi.org/10.1088/1748-9326/ab2a7a.

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Livezey, Robert E.; Hanser, Philip Q.; Public Utilities Fortnightly, *"Redefining Normal Temperatures"*, May 2013.

McMenamin, J. Stuart; Itron presentation on Weather Normalization to NYISO

Yao, S. "Electricity Consumption and Temperature: Evidence from Satellite Data." International Monetary Fund, 2019.

Kentucky Power Company
KPSC Case No. 2025-00338
Commission Staff's Second Set of Data Requests
Dated February 6, 2026

DATA REQUEST

KPSC 2_10 Refer to Kentucky Power's response to Staff's First Request, Item 12.

a. Explain whether Kentucky Power bid on or worked to renegotiate the wholesale power contracts with Olive Hill and the city of Vanceburg.

b. Explain whether Kentucky Power knows the entity supplying power to the two customers.

RESPONSE

a. Given the timing of the cities' requests for quotes in April 2022 to replace the expiring contracts, Kentucky Power did not submit a proposal.

b. The Company is aware that Kentucky Municipal Energy Agency is the entity supplying power to Olive Hill and AEP Energy Partners is the entity supplying power to Vanceburg.

Witness: Lerah M. Kahn

Kentucky Power Company
KPSC Case No. 2025-00338
Commission Staff's Second Set of Data Requests
Dated February 6, 2026

DATA REQUEST

KPSC 2_11 Refer to Kentucky Power's response to Staff's First Request, Item 14. In KPCO_R_KPSC_1_14_Attachment1, provide an explanation of why the unit was placed into Reserve Shutdown. Include in the response the communications with PJM requesting the unit be placed into Reserve Shutdown status.

RESPONSE

KPCO_R_KPSC_1_14_Attachment1 provides information related to scheduled, actual, and forced outages. The process of scheduling planned or maintenance outages are initiated by the Company and approved by PJM, which is distinct from the concept of reserve shutdown. If a unit is not selected to run for economic reasons by PJM, but is available for dispatch, the unit is placed in reserve shutdown status. The unit will remain in reserve shutdown until PJM selects it to run for economic reasons, or if there is an emergency need for the unit to run (the unit is self-committed or "must run"). Reserve shutdown is distinct from the process of scheduling planned or maintenance outages, which are initiated by the Company and approved by PJM. There is no separate communication from PJM to place a unit in reserve shutdown, it is part of the results from their Economic Unit Commitment Study performed on a daily basis.

Witness: Joshua D. Snodgrass

Witness: Jason M. Stegall

VERIFICATION

The undersigned, Kimberly K. Chilcote, being duly sworn, deposes and says she is the Director of Coal and Reagent Procurement for American Electric Power Service Corporation, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Signed by:
Kimberly K. Chilcote
72788EA73A4548E...
Kimberly K. Chilcote

Commonwealth of Kentucky)
) Case No. 2025-00338
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kimberly K. Chilcote, on 2/17/2026 | 9:01 AM EST.

Signed by:
Michelle Caldwell
E9B1BC7AC31F421...
Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires 05/05/2027

Notary ID Number KYNP71841

VERIFICATION

The undersigned, Lerah M. Kahn, being duly sworn, deposes and says she is the Manager of Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of her information, knowledge, and belief.

Lerah Kahn

Lerah M. Kahn

Commonwealth of Kentucky	)	
	)	Case No. 2025-00338
County of Boyd	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lerah M. Kahn, on February 18, 2026

Marilyn Michelle Caldwell

Notary Public

My Commission Expires May 5, 2027

Notary ID Number KYNP71841

MARILYN MICHELLE CALDWELL
Notary Public
Commonwealth of Kentucky
Commission Number KYNP71841
My Commission Expires May 5, 2027

VERIFICATION

The undersigned, Joshua D. Snodgrass, being duly sworn, deposes and says he is the Mitchell Plant Manager, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Signed by:
Joshua D. Snodgrass
D9636277AAEE4D1...
____
Joshua D. Snodgrass

Commonwealth of Kentucky)
) Case No. 2025-00338
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Joshua D. Snodgrass, on 2/16/2026 | 2:04 PM EST.

Signed by:
Michelle Caldwell
E9B1BC7AC31F421...
____
Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires ________May 5, 2027_____

Notary ID Number ______KYNP71841___________

VERIFICATION

The undersigned, Jason M. Stegall, being duly sworn, deposes and says he is the Director of Regulatory Services for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Jason M. Stegall
Jason M. Stegall

State of Ohio)
) Case No. 2025-00338
County Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Jason M. Stegall, on 19th of February, 2026.

Notary Public

Christine Alaine Frankart
Attorney At Law
Notary Public, State of Ohio
My commission has no expiration date
Sec. 147.03 R.C.

My Commission Expires Has no expiration

Notary ID Number 0091229

VERIFICATION

The undersigned, Clinton M. Stutler, being duly sworn, deposes and says he is the Director of Natural Gas Procurement for American Electric Power Service Corporation, that he has personal knowledge of the matters set forth in the foregoing responses and the information contained therein is true and correct to the best of his information, knowledge, and belief.

Signed by:
Clinton M. Stutler
CC257DDF62684C7...

Clinton M. Stutler

Commonwealth of Kentucky)
) Case No. 2025-00338
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Clinton M. Stutler, on 2/18/2026 | 2:03 PM EST.

Signed by:
Michelle Caldwell
E9B1BC7AC31F421...

Notary Public

MARILYN MICHELLE CALDWELL
ONLINE NOTARY PUBLIC
COMMONWEALTH OF KENTUCKY
Commission #KYNP71841
My Commission Expires 5/5/2027

My Commission Expires 05/05/2027

Notary ID Number KYNP71841