Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_1 Refer to the Integrated Resource Plan (IRP), Volume A, Section 2. Explain whether the energy or demand forecast modeling took into account the potential effects of incentives relating to energy usage in the Inflation Reduction Act (IRA). If not, provide a discussion of how the various incentives provided in the IRA could affect energy usage and load forecasts.

RESPONSE

The Company did not take into account forecasted impacts of the IRA in the IRP load forecast, as the IRA had not been passed at the time the load forecast was developed.

While the Company has not studied in detail the potential impacts of the incentives offered under the IRA on energy usage and forecasts, but the impact is expected to be limited. This assumption is based on the income and demographic characteristics of regional early adopters of some of the incentivized IRA initiatives as compared to characteristics in the Company's service territory.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_2 Refer to the IRP, Volume A, Section 2.1, page 27. Kentucky Power stated that over the next 15-year period, Kentucky Power's service territory population is projected to decline by 0.6 percent. Explain the reasons for the projected decline and, if possible, provide supporting evidence.

RESPONSE

The projected decline is consistent with the long-term trend of population decline in Kentucky Power's service area. Over the past 20 years, population declined at a rate 0.6% per year. Over the most recent 10 years population declined at an annual rate of 0.9%. The most recent five years saw service area population decline by 0.8% per year. There does not appear to be any factor present that will cause this trend of decline to reverse.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_3 Refer to the IRP, Volume A, Section 2.5.3, page 39. Explain how the basis for weather normalization is derived.

RESPONSE

The Company uses a thirty-year average of heating and cooling degree-days for normal weather in the forecast period.

Witness: Glenn R. Newman

Kentucky Power Company
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DATA REQUEST

KPSC 1_4 Refer to the IRP, Volume A, Section 2.6.1, page 39 and Figure 6, page 40. Describe the industries comprising the large commercial customer additions.

RESPONSE

The large load addition for the commercial energy forecast is in the cryptocurrency industry.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_5 Refer to the IRP, Volume A, Section 2.6.2, page 42. With the expiration of the Rockport Unit Power Agreement in 2022 and the divestiture of the Mitchell generation units in 2028, Kentucky Power is currently capacity short and will be further short in 2028.

a. Explain whether Kentucky Power has any demand side management/energy efficiency (DSM/EE) programs under consideration or in the development stage.

b. Explain why no new DSM/EE programs are being presented in this case.

RESPONSE

a. The Company is currently completing a Market Potential Study (MPS) and considering new DSM/EE programs anticipated to be filed for Commission approval within the next year. Also see the Company's response to KPSC 1-52(a).

b. The MPS was not scheduled to be completed until after the Company's IRP was submitted. Any new DSM/EE programs identified in the MPS would need to be filed separately from the IRP. The Company's only current DSM/EE program is small with minimal impact. See also the Company's response to KPSC 1-9.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_6 Refer to the IRP, Volume A, Section 2.6.3, page 42.
a. Explain whether Kentucky Power's special contracts with companies engaged in cryptocurrency mining include interruptible provisions, and if so, explain whether those provisions were taken into account when estimating future interruptible load.
b. Provide the number of MWs of interruptible load Kentucky Power currently has and interruptible load it is forecasted to have by 2037.

RESPONSE

a. There were no existing cryptocurrency-related customers at the time the load forecast was developed. While the future load of a cryptocurrency related customer was included in the load forecast, it was not included in the interruptible load available. At the time of the load forecast development, it was not known that the contract would contain interruptible provisions.

b. The Company used approximately 6 MW of interruptible resources for the load forecast. This number is consistent with what has been used for PJM planning purposes. The Company's Load Forecast does not include expectations of future interruptible loads as they have not gone through the PJM vetting process yet. The Company takes a conservative approach to estimating interruptible load for planning purposes.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_7 Refer to the IRP, Volume A, Section 2.7, page 45. Refer also to the IRP, Volume A, Exhibit C-10, page 204.
a. Provide a copy of the Purdue University climate study referenced and explain how the results differ from U.S. Energy Information Administration's extended weather/climate forecasts.
b. Explain what each of the colored lines represent in Exhibit C-10. Also explain how the forecast scenarios were created from the information in the Purdue University study.

RESPONSE

a. and b. The Purdue University study can be found at this site https://ag.purdue.edu/indianaclimate/indiana-climate-report/
KPCO_R_KPSC_1_7_Attachment1 provides a copy of the study.

The Company uses region specific heating and cooling degree-days in its energy models. Normal weather for the load forecast is assumed to be a 30-year average. It is the Company's understanding that EIA uses a 30-year linear trend for weather in its models. EIA had warmer case with cooling-degree days increasing by 1% per year. The Company used the Purdue University study as a basis for weather change in its extreme weather scenario, which had cooling-degree days increasing nearly 2% per year. EIA does not provide an extreme weather scenario in its Annual Energy Outlook.

The dark blue lines are the base load forecast. The green and red lines are the high and low economic forecasts, respectively. The other line is the impact of the weather extreme scenarios on peak demand. The impact of the weather extreme scenario results in the summer peaks being greater, and the winter peaks being somewhat smaller.

Witness: Glenn R. Newman

Indiana's Past & Future Climate:

A Report from the Indiana Climate Change Impacts Assessment

purdue.ag/climatereport

IN CCIA
Indiana Climate Change Impacts Assessment

Indiana's climate is changing

Temperatures are rising, more precipitation is falling and the last spring frost of the year has been getting steadily earlier.

The data, going in some cases back to 1895, show clear trends, and there are no signs of them stopping or reversing. In some cases, these have been slow progressions. But the speed with which these changes occur has increased significantly in recent decades.

Projections show the pace picking up even more speed as heat-trapping gases, produced by humans burning fossil fuels, continue accumulating in the atmosphere. Indiana will continue to warm, more precipitation will fall, and extremely hot days will be common in many parts of the state. These changing climate patterns affect us individually and affect many aspects of our society, including human health, public infrastructure, water resources, agriculture, energy use, urban environments, and ecosystems.

This report from the Indiana Climate Change Impacts Assessment (IN CCIA) describes historical climate trends from more than a century of data and future projections that detail the ways in which our climate will continue to change.

Significant takeaways, which will be detailed later in this report, include:

- **Key finding:** Indiana has already warmed 1.2°F since 1895. Temperatures are projected to rise about 5°F to 6°F by mid-century[1], with significantly more warming by century's end.
- **Why it matters:** A rising average temperature increases the chance of extreme heat and reduces the chance of extreme cold, and it also changes the timing and length of the frost-free season when plants grow. These shifts will impact air quality, extend the growing season and the allergy season, and create more favorable conditions for some pests and invasive species.
- **Key finding:** The number of extremely hot days[2] will rise significantly in all areas of the state. In the past[3], southern Indiana averaged about seven of these days per year, but by mid-century this region is projected to experience 38 to 51 extremely hot days per year.
- **Why it matters:** Extreme heat raises the likelihood of heat-related illnesses, such as heat exhaustion and heat stroke, which can lead to increased hospitalizations and medical costs. Children and the elderly are especially vulnerable. Extreme heat also reduces crop yields, counteracting the benefits of a longer growing season.
- **Key finding:** Extreme cold events are declining. By mid-century, the northern third of Indiana will experience on average only six days per year below 5°F, down from 13 days in the past.
- **Why it matters:** Cold temperatures control populations of disease-carrying insects such as mosquitoes and ticks, as well as forest pests. Warmer winters would allow some of these species to remain active for longer periods or to expand their ranges into Indiana.
- **Key finding:** Average annual precipitation has increased 5.6 inches since 1895, and more rain is falling in heavy downpours. Winters and springs are likely to be much wetter by mid-century, while expected changes in summer and fall precipitation are less certain.
- **Why it matters:** Increased precipitation, especially in the form of heavy rain events, will increase flooding risks and pollute water as combined sewer systems overflow and fertilizers run off of farm fields. Warmer summers with the same or less rain would increase stress on agricultural crops and drinking water supplies.
- **Key finding:** The frost-free season has lengthened by nine days per year statewide since 1895. This trend is projected to continue and intensify. By mid-century, central Indiana's frost-free season is projected to increase by 3.5 to 4.5 weeks compared to the past[3].
- **Why it matters:** Longer growing seasons can increase the productivity of food crops and forests, and could expand crop-production opportunities in northern latitudes or the possibility of double-cropping further south. But they also increase growth of less desirable plants like ragweed and create favorable conditions for some invasive species.

THE DATA

This report is based primarily on two documents developed by the IN CCIA Climate Working Group. Historical trends span the period 1895 to 2016, depending on the specific variable. See Widhalm et al. (2018) for further details on the historical analysis.

Future climate projections presented here are based on averages from 10 global climate models, which we consider to be the most likely outcomes for a given emissions scenario. The projections from those models estimate average climate patterns during three 30-year periods centered around the 2020s (2011 to 2040), 2050s (2041 to 2070) and 2080s (2071 to 2100). Throughout this report, "mid-century" refers to the 30-year period centered around 2050 and "late century" refers to the 30-year period centered around 2080.

Two future greenhouse gas emission scenarios are considered — "medium" and "high." These scenarios follow Representative Concentration Pathways (RCPs) 4.5 and 8.5[4], respectively, which have been used to develop many previous projections summarized by the Intergovernmental Panel on Climate Change. See Hamlet et al. (2019) and Byun and Hamlet (2018) for further details on the future climate analysis.

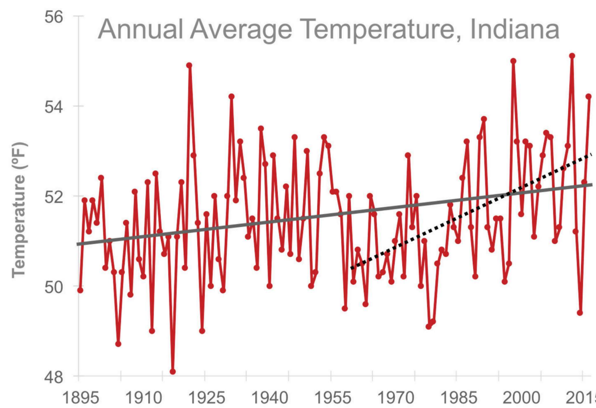
In interpreting the data in this report, it is important to keep in mind that a range of future climates is possible for our state, depending not only on the future rate of greenhouse gas emissions, but also on how the climate system responds to those emissions – not just in the compilations of mathematical equations known as climate models, but in reality. We describe some of the techniques and assumptions that go into this report's projections on page 11.

When using this report or any set of projections from climate models to plan for the future, the reader can place greater weight on outcomes that are projected by most or all models (like the increasing temperatures projected in this report). When different climate models give fairly different projections for a variable (such as for fall precipitation in this report), then more caution should be used. Planning now for a range of possible future climates will be much less risky than counting on one particular outcome.

TEMPERATURES

Since 1895, Indiana's statewide annual average temperature has risen by 1.2°F, or about 0.1°F per decade. When talking about weather — a snapshot of conditions in a particular moment or day — a degree or two of change can happen quickly. However, with climate — the long-term average weather patterns over many decades — a few degrees of change in these averages translates into serious local impacts.

While Indiana's temperature has been rising over the last century, much of that increase has occurred since the 1960s and has already led to much earlier springs than the state experienced a century ago.



Above: *Statewide annual average temperature for Indiana from 1895 to 2016 is shown in red. The black solid line shows the increasing trend in annual temperature (0.1°F/decade) for the period from 1895 to 2016. The black dotted line shows the temperature trend since 1960 (0.4°F"/decade). Source: NOAA Climate at a Glance Database.*

The largest temperature increase has been in spring, when the average temperature has risen 0.2°F per decade (1895 to 2016). Winter and fall have warmed about half as much. And there has been no change in the average summer temperature from 1895 to 2016[5].

The warming trend has sped up in recent decades. Since 1960, the average annual temperature has risen 0.4°F per decade, with warming trends identified in all four seasons. This recent temperature increase has been greatest in winter, at 0.7°F per decade.

Trends in maximum and minimum daily temperatures, averaged over the year, are similar to those of the daily average temperatures.

Indiana Temperature Trends (1895 to 2016)

Variable	Winter	Spring	Summer	Fall	Annual
Tmax	0.1ºF	0.1ºF	- 1ºF	0ºF	0ºF
Tavg	0.1ºF	0.2ºF	0ºF	0.1ºF	0.1ºF
Tmin	0.2ºF	0.2ºF	0.1ºF	0.1ºF	0.2ºF

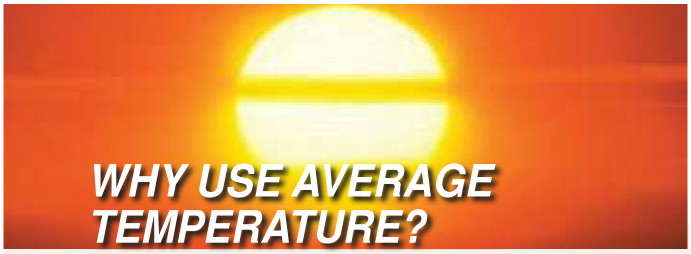
Units = ºF per decade

Indiana Temperature Trends (1960 to 2016)

Variable	Winter	Spring	Summer	Fall	Annual
Tmax	0.5ºF	0.6ºF	0.1ºF	0.2ºF	0.3ºF
Tavg	0.7ºF	0.5ºF	0.3ºF	0.2ºF	0.4ºF
Tmin	0.8ºF	0.5ºF	0.5ºF	0.3ºF	0.5ºF

Units = ºF per decade

Above: *Annual and seasonal temperature trends for Indiana from 1895 to 2016 (top) and from 1960 to 2016 (bottom). Both tables show maximum temperature (Tmax), average temperature (Tavg), and minimum temperature (Tmin). Source: NOAA Climate at a Glance Database.*



WHY USE AVERAGE TEMPERATURE?

Scientists look at annual average temperature as an overall indicator of the state of the climate. Why? Because when you combine temperature measurements for many locations over the course of a year, the values do not fluctuate much from year to year. This makes it easy to identify extreme years and detect short- and long-term trends.

For Indiana, a year's annual temperature might be a degree warmer or colder than the long-term average. When we start getting 2 or 3 degrees from this average, we reach record-setting territory. Future projections have our state's average temperature warming well beyond what we've seen in the past, which explains why a few degrees of change is cause for concern.

INDIANA'S

Top Ten Warmest Years

YEAR	RANK	Degrees Above Average*
2012	1	3.8°F
1998	2	3.7°F
1921	3	3.6°F
1931	4 (tied)	2.9°F
2016	4 (tied)	2.9°F
2017	**6**	**2.7°F**
1991	7	2.4°F
1938	8	2.2°F
2006	9	2.1°F
1946	10	2.0°F

Source: NOAA Climate At A Glance * 1901 - 2000

INDIANA'S

Top Ten Coldest Years

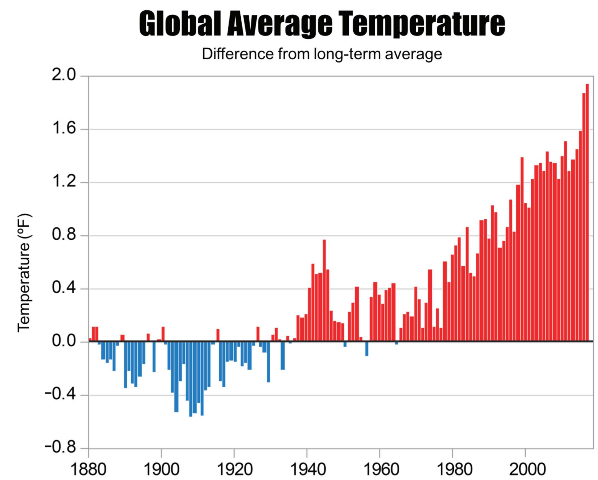
YEAR	RANK	Degrees Above Average*
1917	1	-3.2°F
1904	2	-2.6°F
1912	3 (tied)	-2.3°F
1924	3 (tied)	-2.3°F
1978	3 (tied)	-2.3°F
1979	6	-2.1°F
1958	7 (tied)	-1.9°F
2014	7 (tied)	-1.9°F
1963	9	-1.7°F
1907	10	-1.5°F

Source: NOAA Climate At A Glance * 1901 - 2000

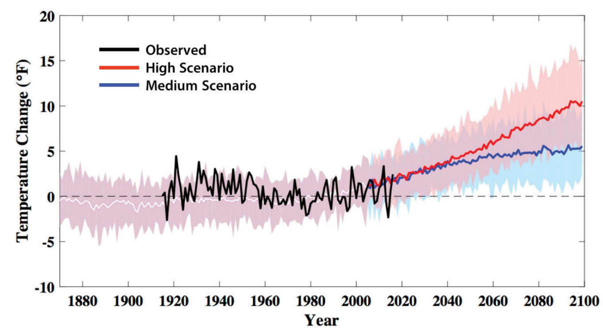
The average global temperature is undergoing similar increases. From 1945 to 1979, there were no records set for hottest global average temperature. Record setting temperatures have happened 12 times since, with 2014, 2015, and 2016 each breaking the record. The 2017 global average temperature ranked third-warmest[6], and that year marked the 41st in a row with above-average temperatures. If the climate were not warming, the chance of randomly having 41 above-average years in a row would be less than one in a trillion.

The warming trends measured in recent decades across Indiana will continue and intensify in the coming decades.

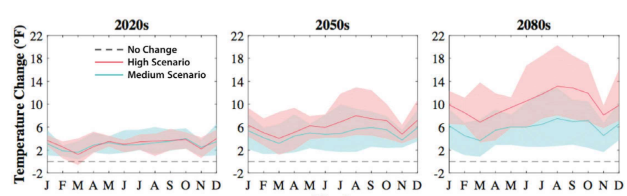
Under the medium- and high-emission scenarios, relative to the recent past[7], Indiana's annual average temperature is projected to increase by about 3°F by the 2020s. By the mid-century, temperatures rise about 5°F under the medium scenario and about 6°F under the high scenario. By late century, the state's average annual temperature reaches about 6°F and 10°F above the historical average[7], respectively, under those scenarios. This increase is projected to be similar in all seasons, although some models suggest the warming will be greatest in summer and fall by late century.



Above: *Difference in the global average temperature (including both land and ocean surfaces) from the long-term average for each year from 1880 to 2016. The long-term average is based on the historical reference period of 1901 to 1960. Red bars show warmer-than-average temperatures, and blue bars show cooler-than-average temperatures. Source: USGCRP 2017.*



Above: *Trajectory of annual mean temperature change for Indiana. The historical reference period is 1971 to 2000. Heavy black line shows Indiana's annual temperature from historical observations (1915 to 2013). Each shaded area represents 95 percent of climate model projections. The most extreme projections are omitted, and colored-lines show the average projection of the 31 remaining models. Source: Byun and Hamlet 2018.*



Above: *Projected changes in monthly average temperature for Indiana for the 2020s (2011-2040), 2050s (2041-2070), and 2080s (2071-2100), relative to a 1971 to 2000 historical baseline. The solid red and blue lines show the 10-model average for the high and medium emissions scenarios, respectively. The shaded areas show the range of results across the 10 climate models. Source: Hamlet et al. (2019).*

Those temperature increases would add to stress on crops such as corn, soybeans, and wheat, and could reduce crop yields. Production of ground-level ozone, a major component of smog, increases with temperature. This diminished air quality would pose a threat to those suffering from asthma or other lung-related illnesses, increasing hospital visits, medical costs and premature deaths[8], as well as harming crops.

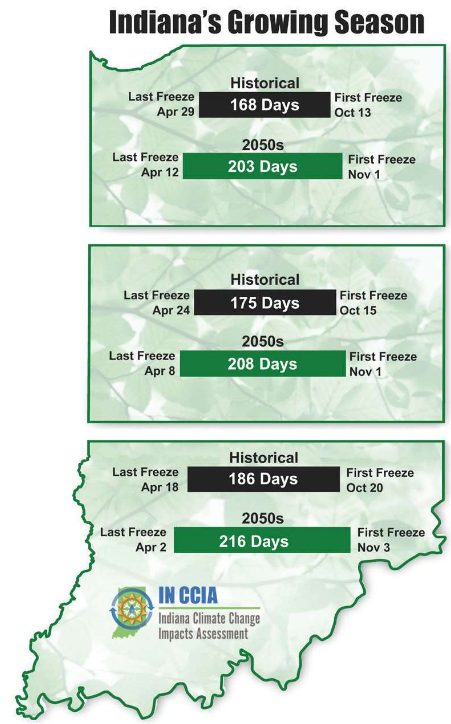
Rising temperatures have already led to a longer growing season. Indiana's frost free season — in which the temperature continuously stays above 32°F — has been extended by an average of nine days beyond what it was in 1915. Eight of those have come in the spring and one in the fall.

This trend is expected to accelerate, as warming temperatures significantly lengthen the growing season throughout the state. Central Indiana historically[3] averaged 175 consecutive frost-free days per year. The region is projected to have 202 under the medium scenario and 208 under the high scenario by mid-century. It's possible that some places could double-crop or northern latitudes could grow a wider variety of crops. Additionally, more consecutive frost-free days would extend the allergy season, which closely follows the length of the growing season. Many birds that migrate according to temperature or daylight cues rely on dropped grain in agricultural fields during migrations. Those species that continue to migrate at the same time could be at a disadvantage as harvest dates move later because that food source would no longer be available to them.

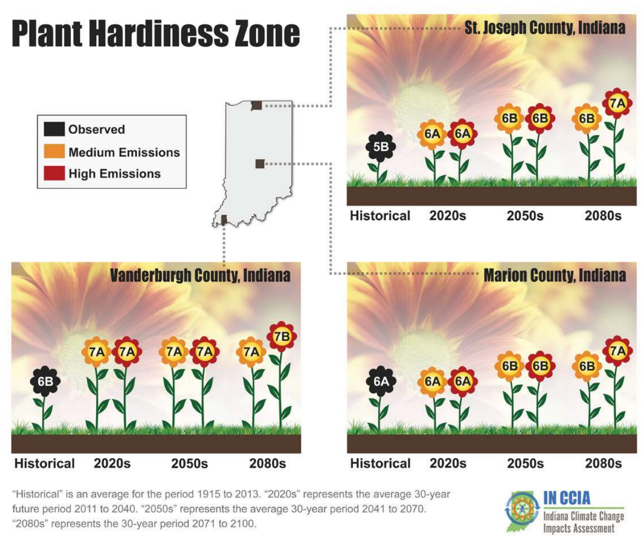
Warming temperatures in the winter months also affect the types of plants that can thrive in Indiana. According to the USDA Plant Hardiness Zones, which are derived from average winter extreme minimum temperatures, the southern tip of Indiana by late century under the high emissions scenario would mimic that of today's northern Alabama plant hardiness (zone 7b).

Changes in Indiana's climate are projected to alter the amount of energy that Hoosiers will need to heat and cool their homes and businesses. Annual heating needs are typically measured in "heating degree days," while cooling demand is measured in "cooling degree days[9]." Historical data show no detectable trend in statewide average heating degree days or cooling degree days per year from the period 1950 to 2016, but as temperatures warm in all seasons by mid and late century, heating and cooling demands will change.

Under the high-emission scenario, rising temperatures will lead to about a fourfold increase in cooling degree days by the 2080s compared to the last century. Heating degree days are projected to decline by about

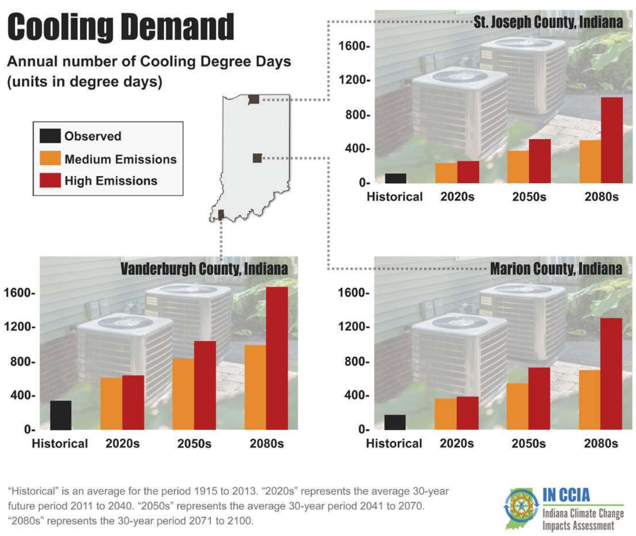


Above: *Growing season length and average first/last freeze dates for northern, central, and southern Indiana. "Historical" is the average for the period 1915 to 2013. For future projections, "2050s" represents the average of the 30-year period from 2041 to 2070 for the high emissions scenario. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

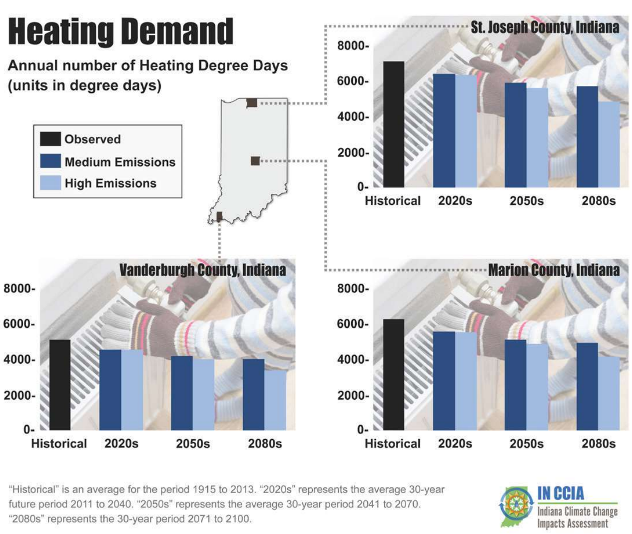


Above: *USDA Plant Hardiness Zones for three Indiana counties. "Historical" is an average for the period 1915 to 2013. For the future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

30 percent. By late this century, people in northern Indiana will run their furnaces only as much as people in southern Indiana did historically. At the same time, though, these northern Hoosiers are expected to run their air conditioners far more often than those in the south did historically.



Above: *Cooling degree days per year for three representative Indiana counties. "Historical" is an average for the period 1915 to 2013. For the future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

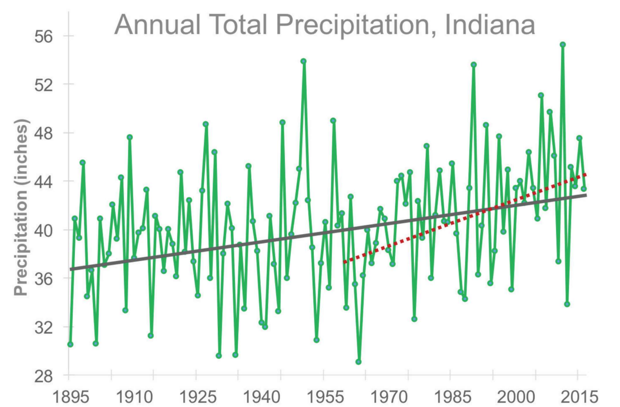


Above: *Heating degree days per year for three representative Indiana counties. "Historical" is an average for the period 1915 to 2013. For the future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

PRECIPITATION

Since 1895, average annual precipitation in Indiana has increased by about 15%, or about 5.6 inches, based on a linear trend. This trend is projected to continue, though the type of precipitation and when it falls are changing and will continue to do so.

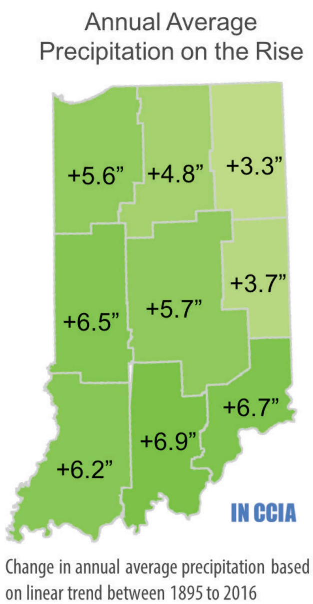
From 1895 to 1959, the state gained 0.32 inches of precipitation per decade. Since then, the rate of precipitation change has increased to 1.33 additional inches per decade, a fourfold increase. This increase is happening in every season, though spring (0.13 inches per decade) and summer (0.19 inches per decade) have increased at a more rapid pace than fall (0.11 inches per decade) and winter (0.03 inches per decade) over the period 1895 to 2016.



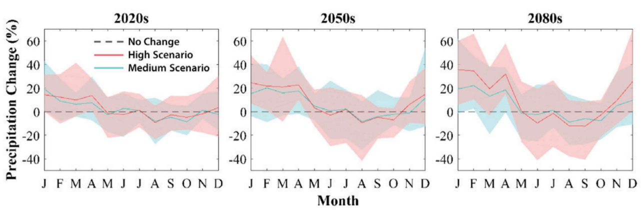
Above: *Statewide annual total precipitation for Indiana from 1895 to 2016. Black solid line shows the increasing trend in annual precipitation (0.46"/decade) for the period from 1895 to 2016. The red dotted line shows the precipitation trend since 1960 (1.33"/decade). Source: NOAA Climate at a Glance Database.*

While precipitation increased throughout the state from 1895 to 2016, some places have seen bigger increases than others. The southern and west-central regions of the state observed the largest increases, while the east-central and northeast observed the smallest. Spring and fall increases were smallest in the north and largest in the south. The opposite was true in summer, when increases were larger in the north and west.

Under both future emission scenarios, annual precipitation is projected to increase. By mid-century, Indiana will see about 6 percent to 8 percent more rainfall than it averaged in the recent past[7], depending on the scenario.



Above: *Increase in annual precipitation for Indiana's nine climate divisions, based on a linear trend, from 1895 to 2016. Source: NOAA Climate at a Glance Database.*

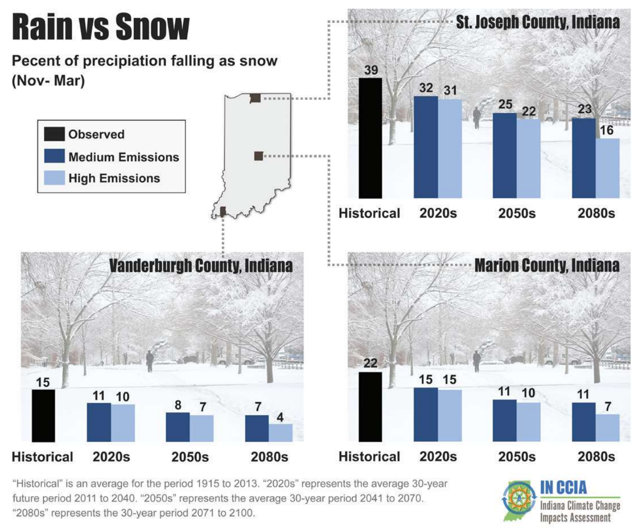


Above: *Projected changes in monthly average precipitation for Indiana for the 2020s (2011-2040), 2050s (2041-2070), and 2080s (2071-2100), relative to a 1971 to 2000 historical baseline. The solid red and blue lines show the 10-model average for the high and medium emissions scenarios, respectively. Shaded areas show the corresponding range of results across the 10 climate models. Source: Hamlet et al. (2019).*

However, the increasing precipitation will not fall evenly across the entire year.

The ten climate models give similar projections for precipitation during some seasons, but not during others. During winter and spring months, nearly all of the climate models suggest increasing precipitation in all three future periods, with greater increases over time for both emission scenarios. There is less certainty, however, in the direction and magnitude of change in the summer and fall months. Relative to the recent past[7], the average of all climate models shows little or no precipitation change in summer and fall during the 2020s, although individual models show increases or decreases. By mid-century, more of the climate models point to drier conditions, but the average change relative to the recent past[7] is still minimal (2 to 3 percent decline). By late century, under the high emissions scenario, summer precipitation is projected to decline by nearly 8 percent, and fall precipitation declines by about 2 percent.

As the climate warms, rain will take the place of much of the snow in the cold season from November through March. In southern Indiana, there will be little snowfall at all by late century under both emission scenarios. In the north, snowfall will be greatly reduced compared to the past[3]. Instances of more than 2 inches of snow will be quite rare in southern Indiana by the 2080s under the high emission scenario. Throughout the state, and under

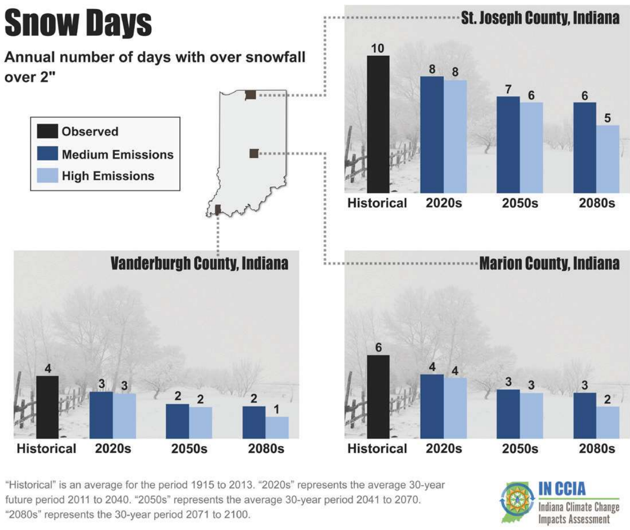


Above: *Percent of cold-season precipitation falling as snow for three Indiana counties. A value of 100 would mean that all precipitation from November to March fell as snow, while a value of 0 would mean none of the precipitation was snow. "Historical" is the average for the period 1915 to 2013. For the future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

both scenarios, snow events of greater than 2 inches happen about half as often by the end of the century.

Fewer snow days would save municipalities and the state money used to plow and salt roadways. Residents are expected to save time and resources used for personal snow removal.

But wetter winters and springs would increase the risk of flooding. Increased precipitation as rain in the winter, when fields are fallow, could wash fertilizer and sediment from farm fields, degrading water quality downstream and reducing crop yields the following growing season. Combined sewer system overflows, an existing problem for many Hoosier communities during high rainfall events, could occur more frequently, dumping sewage into local waterways. Added precipitation in spring may also make it difficult for early agricultural planting as



Above: *Number of days per year with more than 2 inches of snow for three Indiana counties. "Historical" is the average for the period from 1915 to 2013. For the future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

fields could be too muddy for heavy farm machinery to enter. Projections for summer precipitation vary among models, but the average projection of reduced precipitation would increase the risk of water stress in crops, especially when paired with higher temperatures.

Warm-season humidity (May to September) has been on the rise across the state. From 1973 to 2016, average dew-point temperature increased slowly in some places — 0.18°F per decade in South Bend and 0.22°F per decade in Indianapolis— and more quickly in others — 0.73°F per decade in Fort Wayne, 0.62°F per decade in Lafayette, and 0.59°F per decade in Evansville.

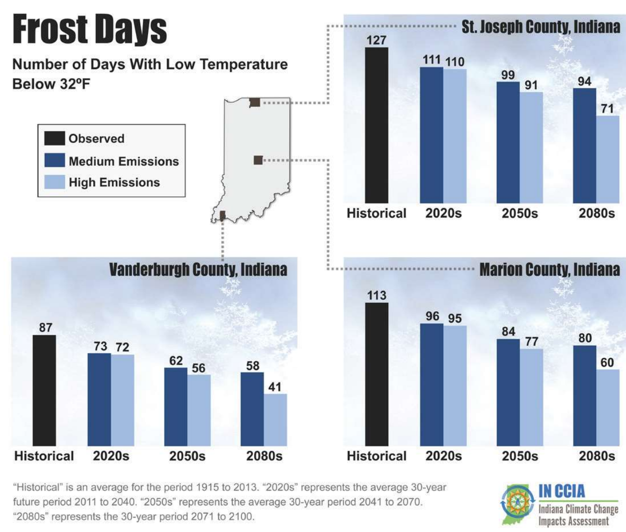
High levels of atmospheric moisture can make temperatures feel hotter, as measured by heat index, which is calculated using air temperature and dew point temperature. Despite rising dew point temperatures, the number of especially high heat index days — those in the top 5 percent of heat index temperatures — does not show a meaningful trend from 1973 to 2016. That suggests that days with high dew point temperatures did not always occur on days with high air temperatures. During the 1990s the frequency of high heat index days declined compared to the 1973 to 1989 period before returning to historical levels from 2000 to 2016.

"American Climate Prospectus: Economic Risks in the United States,"[10] a 2014 report by Rhodium Group, projects an expansion of hot, humid weather throughout the country in the coming decades. The group developed an index of heat stroke risk using wet-bulb temperature, which combines air temperature and humidity. The report predicts that by mid-century (2040 to 2059) much of the Midwest, including Indiana, will experience wet bulb temperatures of 80°F to 86°F for 10 to 30 days each year, up from 1 to 10 days per year in the historical period (1981 to 2010). These conditions are considered dangerous, and much like the hottest summer months in the most humid parts of Texas and Louisiana or the most humid summer days in Washington, D.C., and Chicago today.

EXTREME EVENTS

Climate change is already a suspected factor in a number of extreme events, from hurricanes in the Atlantic to droughts and resulting wildfires in the west. In Indiana, climate change will mostly affect extreme temperatures, precipitation extremes that affect stormwater, and annual peak flows that determine river flooding.

As would be expected with rising temperatures, Indiana has recently experienced a downward trend in extreme cold events. Looking across the full period of record from 1915 to 2013, there was no detectable trend in cold days — defined as days per year in which the daily minimum temperature is below 5°F — or frost days, when the daily minimum temperature is below 32°F. These trends reflect the extremely warm conditions in the 1930s and 1940s. But in the more recent period from 1960 to 2016,



Above: *Frost days per year in three representative Indiana counties. A frost day occurs when the daily low temperature is less than 32°F. "Historical" is the average for the period from 1915 to 2013. For the future projections, "2020s" represents the average 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the period from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

Extreme weather and fire events have cost the U.S. federal government over $350 billion during the last decade (excluding costs related to Hurricanes Harvey, Irma, and Maria in 2017). The U.S. Government Accountability Office said in a 2017 report that costs are likely to rise as our climate changes. By mid-century, federal disaster cleanup costs could nearly double, increasing by $12 billion to $35 billion per year.

A White House report on the threat of carbon pollution in Indiana points to the year 2011, when 11 of the 14 weather-related disasters that cost more than $1 billion in the United States were in the Midwest. In 2008, floods killed 24 people and cost $8 billion in agricultural losses. Those numbers are expected to climb as the region experiences more frequent and extreme heat waves, floods and lake-effect snow due to climate change.

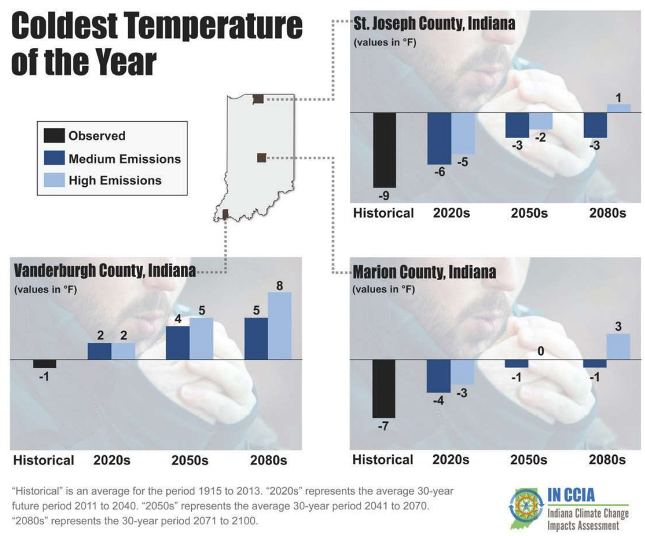
Heavy rains cause 60 combined sewer discharges each year in Indianapolis, sending 8 billion gallons of untreated sewage into the White River and its tributaries, according to a report from the Union of Concerned Scientists. The city is spending more than $2 billion over 20 years to reduce those overflows to four per year. But as heavier rains become more frequent, the city may have to spend more to meet that goal.

On farms, cold winters help keep pests and pathogens in check. But warmer winters will allow pests to spread north and exacerbate disease pressures. U.S. corn producers spend more than $1 billion per year controlling pests, according to the Union of Concerned Scientists report. A study from Purdue University suggests that climate change and its effect on corn pests will substantially increase seed and insecticide costs for those growers and reduce crop yields.

the average number of cold days and frost days both decreased, by nine and eight days per year, respectively.

In both medium- and high-emission scenarios, cold days and frost days decline steadily throughout the 21st century. In the medium scenario, northern Indiana moves from about 15 cold days per year in the past[3] to about six by the 2080s. In the high scenario, there are on average just three cold days per year in the northern part of the state by late century.

The average lowest temperature of the year is expected to rise throughout the state, and by similar amounts from north to south. These temperatures – typically the coldest night of the winter for a given location – are projected to rise by about 6°F by mid-century compared to the average over the last century[3] in both the medium- and the high-emissions scenarios. This puts Indiana at risk for some invasive species and insect

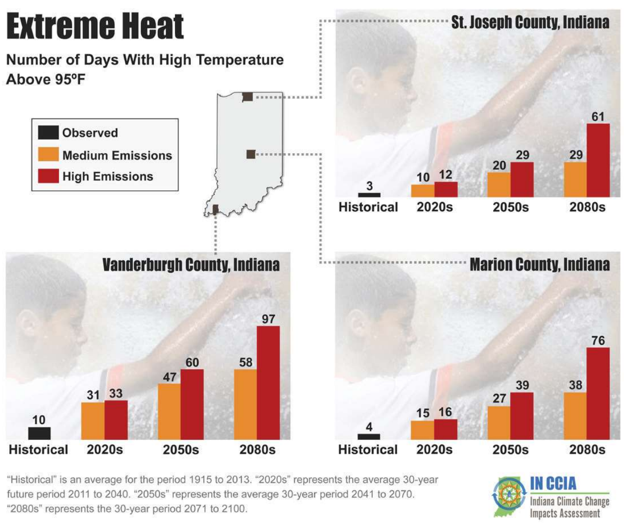


***Above:** Coldest temperature of the year for three representative Indiana counties. "Historical" is an average for the period from 1915 to 2013. For future projections, "2020s" represents the average of the 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

pests that historically would not survive Indiana's coldest winter temperatures.

Even though Indiana's average temperatures have increased over time, the average number of extremely hot days per year decreased from 1915 to 2013. This decline was largely driven by the extremely hot temperatures that occurred with high frequency during the 1930s drought years, which skew the record. During the worst of the heat, both 1933 and 1934 had more than 20 days per year with statewide average temperatures exceeding 95°F. For comparison, the average number of extremely hot days statewide in the recent past[7] was just two per year, though this number varies throughout the state, with more extremely hot days in the south than other areas. There has been no change in the number of extremely hot days per year between 1960 and 2013. This corresponds to the trends seen seasonally, in which summer temperatures have been fairly steady while the other seasons have seen temperatures climb.

But as average temperatures continue to warm, the occurrence of extreme heat events is projected to rise substantially. Extremely hot days[2] increase in both emission scenarios throughout the century with parts

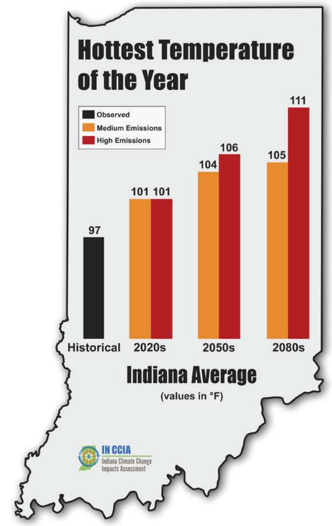


Above: *Extreme heat days per year for three representative Indiana counties. An extreme heat day occurs when the daily high temperature is above 95°F. "Historical" is the average for the period from 1915 to 2013. For future projections, "2020s" represents the average 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

of southern Indiana, such as Evansville (located in Vanderburgh County), projected to experience the most.

Our analysis shows that the state's average hottest temperature of the year is also projected to rise. Over the last century, the average hottest day of the year was 97°F. By mid-century, the hottest temperature of the year is projected to be about 8°F higher than in the past[3] under both emissions scenarios. Elevated high temperatures can create challenges for roadways and pavement as the risk of warping and buckling during the hottest times of the year increases (Chinowsky et al. 2013). The roadway materials used historically may be inappropriate for these new temperatures.

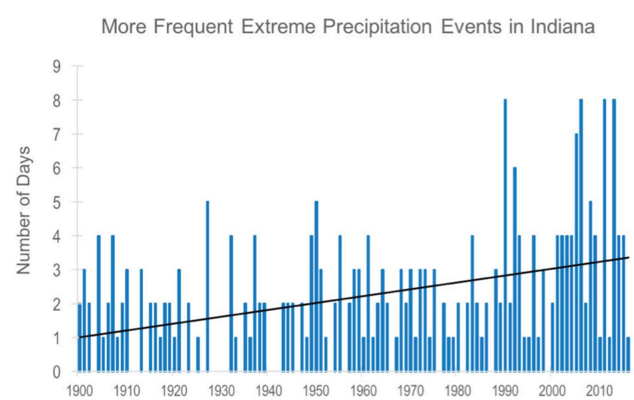
Extreme rainfall events, defined as having a daily rainfall total in the top 1 percent of all events, have increased over the last century and are expected to continue to



Above: *Hottest temperature of the year for Indiana. "Historical" is the average for the period 1915 to 2013. For future projections, "2020s" represents the average 30-year period from 2011 to 2040, "2050s" represents the average from 2041 to 2070, and "2080s" represents the average from 2070 to 2100. Data for other locations and time periods available. Source: Hamlet et al. (2019).*

do so. Heavy downpours contribute to soil erosion and nutrient runoff, which affects both water quality and crop productivity. These events can also overwhelm wastewater systems and create challenges for flood-control infrastructure.

Averaged across the entire state, historically, an extreme rain event occurs when more than 0.86 inches of rain falls in a day. Since 1900, the number of days per year with extreme rain has been increasing by 0.2 days per decade on average. However, most of that increase has occurred since 1990. The northwestern part of the state has seen the largest increase — a rate of about 0.4 days per decade.



Above: *The number of days with precipitation events that exceed the 1900 to 2016 period's 99th percentile for Indiana (statewide average). The black line represents the trend line (0.2 days/decade) for the 1900 to 2016 period. Source: Midwestern Regional Climate Center.*

Regional observations of heavy precipitation in the midwestern U.S. also show that not only are extreme events happening more frequently, but that higher rainfall totals are being measured within these events. Averaged across the Midwest, there has been a 42 percent increase in the amount of precipitation falling in the top 1 percent of events from 1958 to 2016 (USGCRP, 2017). This observed regional trend gives additional support for the validity of the results in Indiana.

Heavy precipitation events are expected to intensify as temperatures rise throughout this century. Preliminary analysis from IN CCIA scientists suggest a one-to-two day increase in the average number of days per year with extreme precipitation. This finding is consistent with other analyses conducted for the midwestern U.S. (Pryor et al., 2014). Additionally, across the Midwest, a twofold to threefold increase in the number of storm events exceeding a two-day five-year return period[11] is projected by late century under the high emissions scenario, with one-day 20-year return period storms increasing by about 20 percent (USGCRP, 2017).

Indiana has about 15 tornadoes per year that rate at least EF1 on the Enhanced Fujita scale, in which EF5 tornadoes are the most damaging. Since 1960, tornadoes have been seen in every month, but mostly in April to June. There is significant variation year to year and no trend in tornado activity.

Warming temperatures could lengthen the storm season, but predictions for future severe storms are difficult to make. Scientists look at the "ingredients," such as instability and vertical wind shear, that can lead to thunderstorms and tornadoes. Those ingredients are expected to increase under a changing climate (Diffenbaugh et a., 2013), but that doesn't necessarily mean that they will lead to increased storm activity or more severe storms.

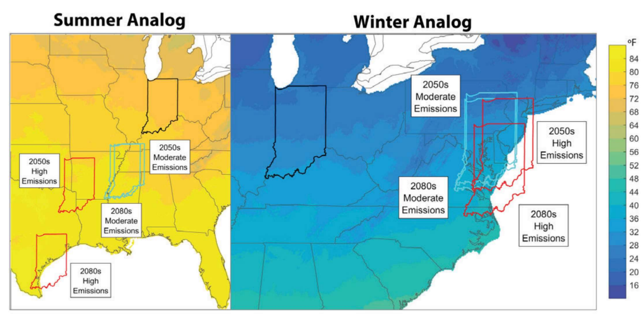
Recently, scientists have begun using models to estimate the likelihood of increased storm activity. Early projections suggest an increase in the frequency and intensity of storms, but considerable uncertainty remains (Gensini and Mote, 2014; Hoogewind et al., 2017).

KEY KNOWLEDGE GAPS

While some trends in Indiana's climate can be estimated from climate models, other aspects remain difficult to predict. For instance, our state receives much of its summer precipitation in storms that are too small in diameter to be represented individually in global climate models. Forecasting how the character of these storms will change is important, but also complicated and time-consuming, and not yet possible for this report. Similarly, there isn't much information on how changes in Lake Michigan's temperature are likely to affect northern Indiana's climate because lake temperatures are not well represented in most models. Research on these and other challenging topics is already underway.

CONCLUSIONS

This assessment documents that significant changes in Indiana's climate have been underway for over a century, with the largest changes occurring in the past few decades. The findings in this assessment highlight the projected future changes using two scenarios representing the rise of heat-trapping gases over the next century. These projections generally suggest that the trends that are already occurring will continue and the rates of these changes will accelerate. They indicate that Indiana's climate will warm dramatically in the coming decades, particularly in summer. Both the number of hot days and the hottest temperatures of the year are projected to increase markedly. Indiana's winters and springs are projected to become considerably wetter, and the frequency and intensity of extreme precipitation events are expected to increase, although more research is needed in this area to better determine the details.



***Above:** An illustration of what Indiana's summer and winter climates will feel like under future scenarios, as compared to today's climate in the United States. The colored Indiana outlines are centered over the regions with the most similar summer (left) and winter (right) climates to the projected future climate of Indiana for medium (blue outlines) and high (red outlines) emissions scenarios. Projections are based on statewide seasonal averages for temperature and precipitation. Underlying maps show current-day seasonal average temperatures based on data from PRISM.*

There is no single place in the United States today that has a climate representative of the projected climate for Indiana. Summers in Indiana will increasingly feel like those we associate with Mississippi, Arkansas, and other states to Indiana's southwest. Winters will feel more like those recently seen in Pennsylvania, New Jersey, and Maryland. These dramatic changes will affect many sectors of our state.

This report serves as a resource for Hoosiers and a starting point for further analyses of how Indiana's economy and resources will be affected by the changing climate. Related data are available online at IndianaClimate.org.

A RANGE OF POSSIBLE FUTURE CLIMATES

We recommend that Hoosiers prepare for a range of possible future climatic conditions.

The future outlook in this report is based on climate models, which are mathematical representations of Earth's climate system based on hundreds of thousands of lines of computer code (or more). Many different research groups around the world have made different models, and these models have been continuously improved over the last several decades.

Even with sophisticated tools like these, no one can predict the future climate with total certainty for a variety of reasons. First, we do not know how people's actions will affect concentrations of heat-trapping gases in the future. Second, there are small chances of unpredictable natural events, such as the eruption of volcanoes. These events affect climate, but are beyond the control of climate scientists.

However, researchers can use climate models to make "projections" of future climate based on reasonable assumptions about future atmospheric conditions. The projections used in this report assume that society will continue to release heat-trapping gases at "medium" or "high" rates.

Even when one of these assumptions is used, responsible scientific projections will still suggest a range of possible future climates. While the models are impressive in their ability to simulate past climates, they do not – and cannot – perfectly represent the enormously complex natural world.

Each of the different models attempts to balance simplicity (to allow faster computations) with complexity (to simulate the most important aspects of the climate system). The various models strike different balances, using different mathematical equations to represent the processes related to climate. These models necessarily depict simplified versions of the world and give somewhat different projections for the future, even when given the same set of assumptions about heat-trapping gases in the atmosphere. For instance, some models depict faster warming than others. Scientists have the most confidence in future projections when many different models produce similar results based on the same set of assumptions.

In creating this outlook for Indiana's climate, we wanted to provide the public with projections that could differentiate future conditions in different parts of the state. Hoosiers know that Indiana's climate is different from north to south, but today's global climate models have relatively low spatial resolution, meaning they may not show patterns like this. To produce more useful results at the state level, we used a procedure called "statistical downscaling" to translate the low-resolution results of the climate model to higher-resolution estimates within a small region. This technique is commonly used and provides the advantage of producing more realistic patterns of climate projections across the state. Of course, this technique also relies on a set of assumptions itself. The performance of downscaling techniques is tested and improved based on past data, but can never be perfect.

The outlook for Indiana's future climate presented in this report relies on projections from 10 global climate models. These projections have been downscaled and analyzed to show how the future climate is likely to vary across the state. For any given time point and emissions level, we interpret the average value across the different models as the most likely future outcome.

However, to fully understand the projections in this report and use them in planning, it is important that readers not only note the main numbers presented, which are typically averages of the projections from the 10 different models, but also the range of results produced by the different models. This gives some indication of the level of agreement among models that a given change will happen.

For instance, in this report, all models suggest that Indiana's climate will become warmer in all seasons, and that this warming will increase over time. In addition, most or all of the models suggest Indiana's winter and spring months will become substantially wetter over time. The consistency of these results across models gives us high confidence in these specific projections.

However, we have less confidence in some of the other projections, such as changes in precipitation during the summer and fall months. During this period, some models suggest minor increases in precipitation while others suggest large decreases. For any given variable, it is useful to understand both the most likely future outcome and the range of possibilities suggested by the different models.

Planning now for a range of possible future climates will be much less risky than counting on one particular outcome.

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IN CCIA Climate Working Group:
- Alan Hamlet, University of Notre Dame (co-lead)
- Mike Baldwin, Purdue University (co-lead)
- Kyuhyun Byun, University of Notre Dame
- Chun-Mei Chiu, University of Notre Dame
- Jill Coleman, Ball State University
- Jeffrey Dukes, Purdue University
- Beth Hall, Midwestern Regional Climate Center
- Kim Hoogewind, Purdue University
- Matt Huber, Purdue University
- Chanh Kieu, Indiana University
- Scott Robeson, Indiana University
- Paul Staten, Indiana University
- Melissa Widhalm, Purdue University
- Jinwoong Yoo, Purdue University

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END NOTES

[1] *Compared to the state's average temperature from 1971-2000.*

[2] *Extremely hot days are defined as ones in which the temperature reaches 95°F or greater.*

[3] *Average from 1915 to 2013*

[4] *To achieve the medium scenario, global greenhouse gas emissions must be significantly reduced almost immediately and peak in the 2040s before declining. Under the high scenario, greenhouse gas emissions continue to increase until late this century. We are currently on the high emissions path.*

[5] *A possible contributing factor to the lack of summer temperature increase is that farmers have boosted plant growth on croplands over the last century. The increased water loss from these crops cools the air (Mueller et al, 2016; Alter et al., 2018).*

[6] *2017 was third-warmest year on record for U.S.: http://www.noaa.gov/news/2017-was-3rd-warmest-year-on-record-for-us*

[7] *Average from 1971 to 2000*

[8] *https://www.cdc.gov/climateandhealth/effects/air_pollution.htm*

[9] *For this report, heating degree days are accumulated when the day's average temperature is less than 68°F, suggesting people may be heating buildings. Cooling days are the opposite, with the day's average temperature above 75°F and people more likely to cool a home or business. A day with an average temperature of 79°F would count as 4 cooling degree days, whereas a day with an average temperature of 55°F would count as 13 heating degree days.*

[10] *http://www.impactlab.org/research/american-climate-prospectus/*

[11] *A return period describes the probability of a storm with a specified intensity happening in any given year. Storm intensity thresholds are unique to each location. A 5-year storm has a 20% chance of happening in any year. A 20-year storm has a 5% chance of happening in any year.*

The Purdue Climate Change Research Center is a faculty-led, non-partisan center supporting interdisciplinary work on climate change. Faculty affiliates work to improve predictions of the rate and impacts of climat change, to develop new technologies to slow the rate of change, and to help people prepare for the future. The center strives to provide useful, science-based information for decision-makers in Indiana and beyond. Learn more at www.purdue.edu/climate

View online: **purdue.ag/climatereport**

IN CCIA
Indiana Climate Change Impacts Assessment

PCCRC
Purdue Climate Change Research Center

March 2018

DATA REQUEST

KPSC 1_8 Refer to the IRP, Volume A, Section 3.2, Figure 12, page 55.
a. Explain whether the Kentucky Power Capacity Obligation is based on Kentucky Power's summer peak demand.
b. Provide an update to Figure 12 with Kentucky Power's winter peak demand and the resulting capacity shortfalls.
c. Provide Figure 12 in tabular form.
d. Provide Figure 12 in tabular form using Kentucky Power's winter peak demand as the capacity obligation.

RESPONSE

a. Confirmed.

b-d: Please see KPCO_R_KPSC_1_8_Attachment1 through KPCO_R_KPSC_1_8_Attachment14 for a copy of all schedules, tables, figures and other assumptions used in the IRP. See KPCO_R_KPSC_1_8_Attachment1 for the Capacity Charts and Reserves worksheet.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_9 Refer to the IRP, Volume A, Section 3.5, page 64. Explain why the market potential study was not discussed in this filing given the plan to add DSM/EE programs in the future.

RESPONSE

Please see the Company's response to KPSC 1-5. As described in section 4.1.1, the EE savings were based on the results of a benchmarking study by GDS Associates, who also is conducting the market potential study ("MPS") referenced in the Company's response to KPSC 1-5. Also see the Company's response to KPSC 1-52(a).

Witness: Brian K. West

Witness: Gregory J. Soller

DATA REQUEST

KPSC 1_10 Refer to the IRP, Volume A, Section 3.6.1, page 67. Provide a list of needed and planned distribution enhancements for Kentucky Power's service territory. Include in the response the issues that each project will address.

RESPONSE

For the list of transmission projects, please see response to KPSC 1_12.
For a list of distribution projects, please see KPCO_R_KPSC_1_10_Attachment1.

Witness: Brian K. West

Witness: Kamran Ali

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_11 Refer to the IRP, Volume A, Section 3.6.4, page 70. Provide a copy of PJM Interconnection LLC's (PJM) Load Deliverability Assessment.

RESPONSE

Please see KPCO_R_KPSC_1_11_Attachment1 for the requested information.

Witness: Kamran Ali

PJM Baseline Reliability Assessment 2022 – 2037 Period

PJM

March 1, 2023

For Public Use

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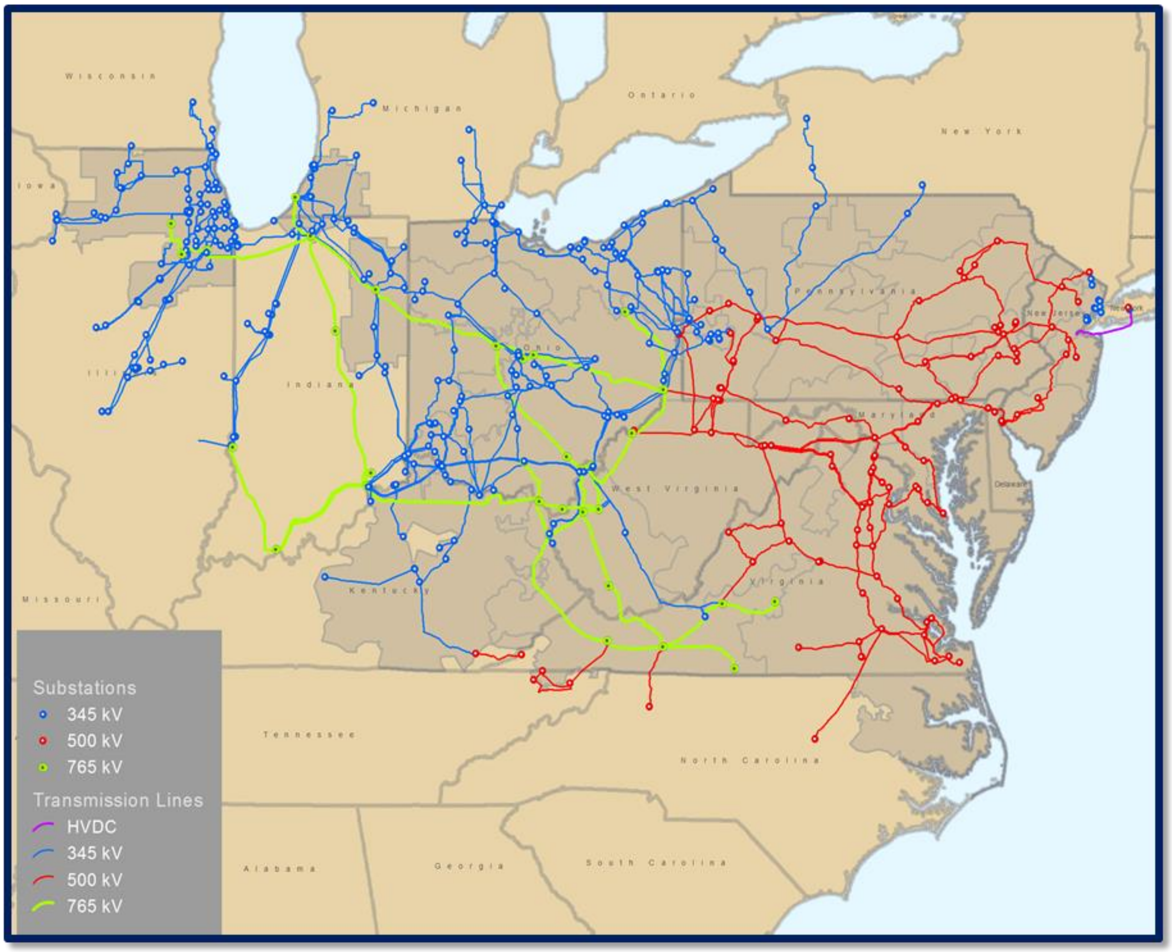
Contents

Introduction

The PJM system covers more than 369,000 square miles in 13 states and the District of Columbia. Serving approximately 65 million people, the PJM system includes major U.S. load centers from the western border of Illinois to the Atlantic coast including the metropolitan areas of Baltimore, Chicago, Cleveland, Columbus, Dayton, Newark, Norfolk, Philadelphia, Pittsburgh, Richmond, and Washington D.C. PJM dispatches more than 180,000 megawatts of generation capacity over more than 84,000 miles of transmission lines – a system that serves nearly 21 percent of the U.S. economy. The PJM system is electrically continuous and consists of multiple electrical service territories. PJM's Bulk Electric System (BES) includes a robust network of 765kV, 500kV, 345kV, 230kV, 161kV, 138kV, and 115kV facilities. The map below depicts the PJM service territory footprint overlaid with PJM high voltage lines operated at 345 kV and above.



Map 1. Existing PJM 345 kV, 500 kV, and 765 kV Network

As a Federal Energy Regulatory Commission (FERC) approved Regional Transmission Organization (RTO), one of PJM's core functions encompasses regional transmission planning. PJM is also a North American Electric Reliability Corporation (NERC) registered Reliability Coordinator, Planning Coordinator, and Transmission Planner. PJM's annual planning process is known as the PJM Regional Transmission Expansion Plan (RTEP). The RTEP process is established in the PJM Operating Agreement – Schedule 6 – Regional Transmission Expansion Planning Protocol. The RTEP processes and procedures are described in detail in the PJM Regional Transmission Planning Process Manuals. PJM Manual 14B – PJM Region Transmission Planning process contains the process used to complete the annual baseline reliability assessment.

PJM's Regional Transmission Expansion Plan (RTEP) identifies transmission upgrades and enhancements that are required to preserve the reliability of the transmission system. The PJM system is planned such that it can be operated to applicable System Operating Limits (SOL) while supplying projected customer demands and projected firm transmission service over a range of forecast system demands under contingency conditions that have a reasonable probability of occurrence. PJM reliability planning encompasses a comprehensive series of detailed analyses that ensure reliability and compliance under the most stringent of the applicable NERC, Regional Entity (RFC or SERC as applicable), PJM, and local criteria. To accomplish this each year, a baseline assessment is completed for applicable facilities over the near term (1-5 years) and longer term (years 6-15). All Bulk Electric System (BES) facilities are included in the RTEP baseline assessment process as required by NERC Standards.

PJM is registered with the North American Electric Reliability Corporation (NERC) as the Reliability Coordinator (RC), Interchange Authority (IA), Transmission Operator (TOP), Balancing Authority (BA), Planning Coordinator (PC), Transmission Planner (TP), Transmission Service Provider (TSP), and Resource Planner (RP). There are multiple transmission zones within PJM. Table 1 lists individual transmission zones in the PJM footprint. A few smaller PJM transmission owners are modeled within another larger PJM transmission area and are not explicitly listed on this table. A few examples of this are Neptune Regional Transmission System LLC, Linden VFT LLC, and Essential Power/Rock Springs.

AP	Allegheny Power System, Inc.
AE	Atlantic Electric
AEP	American Electric Power Co., Inc.
ATSI	American Transmission Systems, Inc.
BG&E	Baltimore Gas & Electric Co.
CE	Commonwealth Energy System
DAY	Dayton Power and Light Co
DEO&K	Duke Energy Ohio and Kentucky
DLCO	Duquesne Light Co
DP&L	Delmarva Power and Light Co
EKPC	Eastern Kentucky Power Cooperative
ITCI	ITC Interconnection
JCP&L	Jersey Central Power and Light
METED	Metropolitan Edison Co
OVEC	Ohio Valley Electric Corporation
PECO	PECO Energy Co.
PENELEC	Pennsylvania Electric Co
PEPCO	Potomac Electric Power Co.
PPL	PPL Electric Utilities
PSE&G	Public Service Electric and Gas Company
RECO	Rockland Electric Company
UGI	UGI Utilities Inc.
DVP	Virginia Power (Dominion)

Table 1. **PJM area Transmission Zones**

PJM is interconnected with neighboring systems and has over 100 BES transmission ties to these adjacent systems. Table 2 lists PJM's neighboring systems and associated entities. PJM coordinates planning analyses with adjacent Planning Coordinators and Transmission Planners to ensure that contingencies on adjacent systems are studied as part of PJMs RTEP process.

ALTE	Alliant Gas and Electric – East
ALTW	Alliant Gas and Electric – West
AMIL	Ameren Illinois
AMMO	Ameren Missouri
BREC	Big Rivers Electric Corporation
CPLE	Carolina Power and Light Company - East
CPLW	Carolina Power and Light Company - West
DEI	Duke Energy Indiana
DUKE	Duke Energy Carolinas
IPL	Indianapolis Power and Light Company
ITCT	International Transmission Company
LAGN	Louisiana Generating Company
LGEE	LGE Energy
LIPA	Long Island Power Authority
MEC	MidAmerican Energy
METC	Michigan Electric Transmission Co.
National Grid	National Grid
NIPS	Northern Indiana Public Service Company
NYISO	New York ISO
OMU	Owensboro Municipal Utilities
ORU	Orange & Rockland
SMT	Brookfield/Smoky Mountain Hydropower LLC
SIGE	Southern Indiana Gas & Electric Company
TVA	Tennessee Valley Authority
WEC	Wisconsin Electric Power Company

Table 2. **PJM Neighboring Systems**

The PJM RTEP process requires that cost responsibility for facility enhancements be established. In order to establish a starting point for development of Regional Transmission Expansion Plans and determine cost responsibility for expansion facilities, a 'baseline' assessment of system adequacy and security is necessary. The purpose of this assessment is threefold:

1. To identify areas where the system as planned under previous assessments does not meet the applicable reliability criteria and standards as a result of load increases on the system or changes to methodologies associated with the analyses.
2. To develop and recommend facility expansion plans which will bring areas where the system does not meet performance requirements specified in an applicable standard into compliance. These plans include cost estimates and required in-service dates.
3. To establish what will be included as baseline costs in the allocation of the costs of expansion for those generation and merchant transmission projects proposing to connect to the PJM system.

The system as planned is evaluated for its compliance with all applicable reliability standards to accommodate the forecast demand, committed resources, and commitments for firm transmission services for a specified time frame. Areas that are found to not meet applicable reliability criteria are identified and enhancement plans are developed to achieve compliance within an identified timeframe. The lead time necessary to implement the system enhancement is considered as part of the overall plan. In addition, the status and progress of each upgrade is tracked closely to ensure that the required in-service dates are met.

The 'baseline' assessment and the resulting expansion plans serve as the base system for the conduct of Interconnection Feasibility Studies and System Impact Studies associated with new generation, merchant transmission and long term firm transmission service. The interconnection process is described by Manual 14A: Generation and Transmission Interconnection Process. This report details the results of the 'baseline' assessment from 2022 through 2037 for the PJM footprint.

Executive Summary

PJM is responsible for the development of a Regional Transmission Expansion Plan (RTEP) for the PJM system that will meet the needs of the region in a reliable, economic and environmentally acceptable manner. As further described in following portions of this assessment, the PJM RTEP combines a broad set of analysis into a single plan. The annual RTEP process consists of a baseline reliability review, analysis to identify the transmission needs associated with both generation interconnection and merchant transmission, review of conditions experienced in real time operations, inter-regional reliability analysis, and many other special studies. The RTEP incorporates the unique needs identified by in-depth thermal, stability, short circuit, and voltage reliability analysis. PJM ensures a robust and comprehensive annual RTEP by incorporating all of these diverse needs into a single plan.

The annual RTEP planning assessment includes a comprehensive review of PJM Bulk Electric System (BES) facilities as required by NERC standards TPL-001-4. PJM maintains a series of power flow, short circuit and stability cases that represent a range of critical system conditions for a range of forecast demand levels and study years. The annual RTEP baseline analysis performs the following tests at a minimum to ensure NERC TPL compliance:

1) Thermal Analysis
    a) Normal system (all facilities in service), single, and multiple contingency analysis as required by NERC TPL standards
    b) Generation deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    c) Common mode outage procedure analysis, as described in PJM Manual 14B Section 2 RTEP Process
    d) Load deliverability analysis, as described in PJM Manual 14B Section 2 RTEP Process
    e) N-1-1 analysis
    f) Light Load Reliability Analysis
    g) Winter Reliability Analysis
    h) 15 Year Analysis
    i) Transfer Limit Analysis
2) Short Circuit fault duty analysis
3) Voltage Analysis
    a) Voltage limit testing, including voltage magnitude and voltage drop monitoring for many of the test methods listed above for the thermal analysis
    b) Voltage collapse, including non-convergent events
    c) PV analysis, including Transfer Limits
4) Stability Analysis
    a) Transient stability (short and long term)
    b) Small signal stability (oscillations)
    c) Voltage Stability
    d) Nuclear Plant Interface Requirements (NPIR)

PJM also studies, requests for new generation, merchant transmission, and long term firm transmission service. The process for studying these requests is described in PJM Manual 14A. In Calendar year 2022, PJM completed 594 system impact studies to accommodate new generation, merchant transmission, and long term firm transmission service. The 2022 RTEP includes any upgrades associated with the queue projects that are required to maintain the reliability of the PJM system.

1) New Services Queue Analysis
   a) Generation interconnection
   b) Merchant transmission
   c) Yearly long term firm transmission service

Information related to the generation, merchant transmission, and yearly long term firm transmission service request queues can be found on the PJM website at the following link.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Information that is posted on the PJM website includes the status of the New Services Queues, as well as the technical study reports. The technical reports include the feasibility, impact, and facility study reports. PJM agreements such as interconnection service agreements (ISA) and interconnection construction service agreements (CSA) are also posted on the website.

PJM coordinates inter-regional activities with neighboring systems pursuant to PJM's Tariff and interregional agreements. PJM annually participates in a wide range of inter-regional groups and committees. Several significant efforts in 2022 are listed below.

1) Inter-regional planning groups
   a) Independent System Operator / Regional Transmission Organization (ISO/RTO) Council (IRC)
   b) Eastern Interconnection Planning Collaborative (EIPC): Planning Coordinators of the Eastern Interconnection
      i) DOE National Transmission Study
      ii) Workshops on Transmission Planning for High Penetration of Renewable Resources
      iii) Workshops on Minimum Interregional Transfer Capability approach
   c) Joint Operating Agreement with New York ISO (NYISO) and Joint Operating Agreement with Mid-Continent ISO (MISO)
      i) Joint ISO/RTO Planning Committee (JIPC) activities pursuant to the PJM/NYISO/ISO-NE Northeast Planning Coordination Protocol
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability Interconnection Queue and Market Efficiency Analysis
      ii) Joint RTO Planning Committee (JRPC) activities pursuant to the MISO/PJM Joint Operating Agreement
         (1) Interregional Planning Stakeholder Advisory Committee (IPSAC) – Reliability and Market Efficiency Analysis
   d) Southeastern Regional Transmission Planning: (SERTP)

i) Joint Operating Agreement with Duke Energy Progress (DEP)
ii) Joint Operating Agreement with Tennessee Valley Authority (TVA)

e) Joint Reliability Coordination Agreement between PJM and TVA
f) North Carolina Transmission Planning Collaborative (NCTPC) planning and data sharing agreement

2) North American Electric Reliability Corporation (NERC) and Eastern Interconnection Reliability Assessment Group (ERAG) related activities
   i) SERC Reliability Corporation and associated committees and working groups
   ii) RFC Reliability Corporation and associated committees and working groups

PJM Planning also coordinates with PJM Operations to review operational performance issues. In addition, sensitivity studies may be requested by stakeholders. Examples of these studies include:

Additional Studies

- Investigation of Susquehanna N-1-1 oscillation issue (PPL)
- Investigation of Calvert Cliffs N-1-1 oscillation issue (BGE)
- Peach Bottom event analysis (PECO)
- Conowingo damping issue verification (PECO)

The RTEP assesses the needs of the system, at peak load for year one, two, three four and year 5 in the near term and over the longer term (up to 15 years) to identify baseline transmission enhancements that require more time to implement. Additionally, PJM evaluates an off peak load seasonal assessment for year 5 PJM also is responsible for recommending the assignment of any transmission expansion costs to the appropriate parties. In order to carry out these responsibilities, it is necessary to establish a starting point or 'baseline' from which the need and responsibility for enhancements can be determined.

As the NERC registered Planning Coordinator, PJM is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems for both the near term and longer term. The planned network upgrades required by the RTEP serve as a central repository for the BES related reliability plans of the individual PJM transmission owners. By integrating the individual plans into a single plan, the RTEP is able to provide a robust reliability plan for the PJM Bulk Electric System.

In order to establish the long term plan, PJM has defined the fifteen (15) year period from 2022 through 2037 as the 2022 "baseline" planning period. This assessment is inclusive of the previous years' baseline assessments, models, and required upgrades. As such, the existing system plus any planned modifications to the transmission system including reactive resources that are scheduled to be in service prior to the 2027 summer peak period were chosen as the base system for the near-term assessment. This ensures the system as planned remains compliant with reliability standards. Appendix A represents a snapshot of all upgrades identified in RTEP evaluations prior to 2022. These identified upgrades, when added to the previously existing system, function as the base system for future

models. In addition, assessments for delivery years prior to 2027 were updated with current assumptions to validate the on-going need for identified upgrades and to ensure continued compliance with reliability criteria.
For the 2022 RTEP cycle, PJM has studied 22 generator deactivation notifications resulting in over 4,400 MW of existing generation deactivating in 2022 or some point in the near term planning horizon. In order to establish a model which accurately included all expected generation retirements, PJM performed many sets of analysis to study the effects of these generation retirements on the system. Baseline transmission upgrades were identified as a result of these deactivations. The upgrades resulting from the deactivations were examined in the basecase before approving new RTEP upgrades for any of the standard RTEP analysis for the 2022 RTEP cycle. The scope of the deactivation notification analysis was significant and included a review of system impacts in years 2022 through 2027. The scope and results of the generation deactivation analysis is discussed in subsequent sections of this report.

All new generation and merchant transmission projects that executed an Interconnection Service Agreement were also included in this baseline system along with any associated transmission enhancements as identified in the System Impact Studies associated with those requests. Queued generation, merchant transmission, and firm transmission service is studied and subsequently included in the basecase for the New Services Queue studies. The process for these studies is detailed in PJM manual 14A. PJM manual 14B attachments A-I describe the analysis that is performed to ensure the reliability of new generation, merchant transmission, and firm transmission service. Any supplemental transmission enhancements independent of those associated with new generation or merchant transmission projects were also included. All firm transmission service currently committed for the period was represented.

PJM has conducted a comprehensive assessment of the ability of the PJM system to meet all applicable reliability planning criteria. The applicable reliability planning criteria are listed below:

- NERC Planning Standards
  http://www.nerc.com/pa/Stand/Pages/default.aspx
- RFC Reliability Standards
  https://rfirst.org/ProgramAreas/Standards/Regional/Pages/Regional.aspx
- SERC Reliability Corporation
  http://www.serc1.org/Application/HomePageView.aspx
- PJM Reliability Planning Criteria as contained in PJM Regional Transmission Planning Process Manuals http://www.pjm.com/library/manuals.aspx
- Transmission Owner Reliability Planning Criteria as filed in their respective FERC Form 715 filing http://www.pjm.com/planning/planning-criteria/to-planning-criteria.aspx

In completing this assessment, PJM has documented all conditions where the system did not meet applicable reliability criteria and identified the system reinforcements required to bring the system into compliance along with estimated cost and lead-time to implement them.

Those areas that were found to not meet applicable reliability standards establish the need for reinforcement in those areas independent of any future interconnection projects not included in the baseline analysis. The resulting system with the identified reinforcements to bring the system into compliance, is anticipated to be used in evaluating the impact of the projects in queues AF1 and AF2 that qualify and elect to proceed with the system impact studies. The extent to which reinforcements identified in the baseline assessment are advanced, deferred, modified or eliminated will be used in determining cost responsibility for the final plans in the RTEP.

It should be recognized that the reinforcements identified in this baseline analysis may be modified, advanced, deferred or eliminated as a result of future system assumptions. Future assumptions include generation projects, merchant transmission projects, generation retirements, or transmission service being added to or removed from the system. The development of the RTEP for PJM is an ongoing process, which includes the conduct of system impact studies and development of plans to accommodate the new interconnection projects. Upon completion of the system impact studies some projects may elect not to proceed. When it is determined which projects will commit to proceed, PJM develops a new baseline RTEP to meet the needs of the region, including the accommodation of all new projects committed to connect, during the next 5 year period.

Key Findings

Inclusive of the baseline upgrades identified in the Results Section of this assessment, PJM assesses its system as being compliant with the thermal, reactive, short circuit, and stability requirements of all applicable standards including NERC Standards TPL-001-4 for both the near term and longer term. The results section of this assessment includes all planned upgrades needed to meet the performance requirements of Table 1 in each respective TPL standard throughout the planning horizon.

The reinforcements identified as part of the 2022 RTEP that are required to achieve compliance having an estimated cost of at least $5 million are described below. The required in-service date of these upgrades is also included. A complete list of projects along with detailed descriptions of the conditions that are driving the need for them, are described in the Results section and Appendix A of this report. PJM staff from the Infrastructure Coordination group coordinates with the transmission owners and generation or merchant transmission developers to monitor project schedules for implementation of these reinforcements and coordinate any required outage activities to ensure these reinforcements are completed by their required in-service dates. The cost estimates below are based on those provided by the responsible entities and discussed at the monthly Transmission Expansion Advisory Committee (TEAC) meetings during the calendar year.

PJM MID ATLANTIC

AEC

- Rebuild the underground portion of Richmond-Waneeta 230 kV. - 6/1/2029 - $16.00M

BGE

- Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild which is 2.16 miles. - 6/1/2029 - $9.92M
- Rebuild 1.4 miles of existing single circuit 230 kV tower line between BGE's Graceton substation to the Brunner Island PPL tie-line at the MD/PA state line to double circuit steel pole line with one (1) circuit installed to uprate 2303 circuit - 6/1/2027 - $8.40M
- Reconductor two (2) 230 kV circuits from Conastone to Northwest #2 - 6/1/2027 - $37.76M

DPL

- Rebuild the New Church - Piney Grove 138 kV line - 6/1/2027 - $63.00M

JCPL

- Add third Smithburg 500/230 kV transformer. - 12/31/2027 - $13.40M
- Atlantic 230 kV substation – Convert to double-breaker double-bus. - 6/1/2030 - $31.47M
- Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line. - 6/1/2029 - $206.48M
- G1021 (Atlantic-Smithburg) 230 kV upgrade. - 6/1/2030 - $9.68M
- Larrabee Collector station-Larrabee 230 kV new line. - 6/1/2029 - $7.52M

- Larrabee Collector station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line. - 12/31/2027 - $150.35M
- Larrabee-Oceanview 230 kV line upgrade. - 6/1/2030 - $6.00M
- New Larrabee Collector station-Atlantic 230 kV line. - 6/1/2030 - $17.07M
- R1032 (Atlantic-Larrabee) 230 kV upgrade. - 6/1/2030 - $14.50M
- Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63. - 6/1/2029 - $11.45M
- Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line. - 12/31/2027 - $62.85M
- Rebuild Larrabee-Smithburg No. 1 230 kV. - 12/31/2027 - $44.77M
- Reconductor Red Oak A-Raritan River 230 kV. - 6/1/2029 - $11.05M
- Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV. - 6/1/2029 - $25.88M
- Smithburg substation 500 kV expansion to 4-breaker ring. - 12/31/2027 - $68.25M

LS POWER

- Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line. - 6/1/2029 - $61.20M

MAOD

- Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. - 12/31/2027 - $121.10M

ME

- Install a new Allen four breaker ring bus switchyard near the existing MetEd Allen substation on adjacent property presently owned by FirstEnergy. Terminate the Round Top-Allen and the Allen-PPGI (PPG Industries) 115 kV lines into the new switchyard. - 6/1/2026 - $6.41M
- Install second TMI 500/230kV Transformer with additional 500 and 230 bus expansions - 6/1/2027 - $30.19M
- Rebuild/Reconductor the Germantown - Lincoln 115 kV Line. Approximately 7.6 miles. Upgrade limiting terminal equipment at Lincoln, Germantown and Straban - 6/1/2027 - $17.36M

PECO

- Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles. - 6/1/2029 - $18.82M
- Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA. - 6/1/2029 - $5.60M

PENELEC

- At Maclane tap: Construct a new three breaker ring bus to tie into the Warrior Ridge - Belleville

46 kV D line and the 1LK line - 6/1/2027 - $10.09M

Replace the Shawville 230/115/17.2 kV transformer with a new Shawville 230/115 kV transformer and associated facilities. Replace the plant's No. 2B 115/17.2 kV transformer with a larger 230/17.2 kV transformer. - 6/1/2026 - $8.78M

- Purchase one 80 MVAR 345 kV spare reactor, to be located at the Mainesburg station. - 12/1/2022 - $6.44M
- Rebuild 6.4 miles of the Roxbury - Shade Gap 115 kV line from Roxbury to the AE1-071 115 kV ring bus with single circuit 115 kV construction - 6/1/2027 - $15.03M
- Rebuild 7.2 miles of the Shade Gap - AE1-071 115 kV line section of the Roxbury - Shade Gap 115 kV line - 6/1/2027 - $17.43M

PPL

- At the existing PPL Williams Grove substation, install a new 300 MVA 230/115 kV transformer. - 6/1/2026 - $6.30M
- Construct a new ~3.4 mile 115 kV single circuit transmission line from Williams Grove to Allen substation. - 6/1/2026 - $5.11M
- Reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another. - 6/1/2027 - $10.70M

PSEG

- Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work. - 12/31/2027 - $5.53M
- Construct a new 69kV line from 14th Street to Harts Lane - 6/1/2027 - $34.40M
- Construct a third 69kV supply line from Totowa substation to the customer's substation - 1/1/2025 - $8.20M
- Convert existing Medford 69kV Straight bus to Seven breaker ring bus, construct a new 69kV line from Medford to the Mount Holly station, and install a capacitor bank at Medford - 6/1/2027 - $78.70M
- Convert Locust Street 69kV from a Straight Bus to a Ring Bus. - 6/1/2027 - $30.00M
- Convert Maple Shade 69kV from a Straight Bus to a Ring Bus - 6/1/2027 - $33.90M
- Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV. - 12/31/2027 - $24.92M
- Replace existing 230/138 kV Athenia No. 220-1 transformer. - 6/1/2026 - $13.04M
- Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard - 6/1/2026 - $13.36M

Transource

- Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration). - 6/1/2029 - $76.27M

PJM WEST

AEP

- Hayes 138 kV: Build a new 4-138 kV circuit breaker ring bus. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner –Randolph 138 kV line connection. - 6/1/2027 - $7.44M
- Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV - 12/1/2027 - $58.52M
- Rebuild the 1.8 mile 69kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR. - 6/1/2027 - $5.10M
- Rebuild the existing Darrah-Barnett 69 kV line, approximately 2.8 miles and replace a riser at Darrah station. - 12/1/2027 - $6.98M
- Rebuild the George Washington – Kammer 138 kV circuit, except for 0.1-mile of previously-upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right-of-way as needed. - 6/1/2027 - $18.30M
- Replace the Jug Street 138kV breakers M, N, BC, BF, BD, BE, D, H, J, L, BG, BH, BJ, BK with 80KA breakers - 6/1/2024 - $14.00M
- Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit. - 12/1/2027 - $11.15M
- Terminate the existing Broadford – Wolf Hills #1 138 kV line into Abingdon 138 kV Station. This line currently bypasses the existing Abingdon 138 kV Station; Install two new 138 kV circuit breakers on each new line exit towards Broadford and towards Wolf Hills #1; Install one new 138 kV circuit breaker on line exit towards South Abingdon for standard bus sectionalizing - 6/1/2027 - $8.48M

APS

- Reconductor 27.3 miles of the Messick Road - Morgan 138 kV Line from 556 ACSR to 954 ACSR. At Messick Road Substation: Replace 138 kV wave trap, circuit breaker, CT's, disconnect switch, and substation conductor and upgrade relaying. At Morgan Substation: Upgrade Relaying – 6/1/2027 - $49.23M
  Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV #3 transformer. Upgrade relaying at Black Oak substation. - 6/1/2027 - $17.37M
- Scope Change: During 2027 RTEP analysis, it was determined that the topology change caused the new AA2-161 to Charleroi line to be overloaded. The new overload is conductor limited and the cost to upgrade 12.8 miles is $32 M. As a result, the cost-effective solution is to alternatively reconductor Yukon to AA2-161 ckt 1 & 2 while maintaining the existing topology. The cost to upgrade is $10.64 M Expand the future AA2-161 138 kV six (6) breaker ring bus into an eleven (11) breaker substation with a breaker-and-a-half layout by constructing five (5) additional breakers and expanding the bus. Loop the Yukon - Charleroi #2 138 kV line into the future AA2-161 substation. Relocate terminals as necessary at AA2-161. Upgrade terminal equipment (wavetrap, substation conductor) and relays at Yukon,

Huntingdon, Springdale, Charleroi, and the AA2-161 substation. - 6/1/2026 - $10.64M

ATSI

- Rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR. - 6/1/2027 - $10.40M
- Rebuild the Abbe-Johnson #2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman. - 6/1/2027 - $10.90M

Dayton

- New Westville – West Manchester 138kV Line: Construct a new approximate 11-mile single circuit 138kV line from New Westville to the Lewisburg tap off 6656. Convert a portion of 6656 West Manchester – Garage Rd 69kV line between West Manchester - Lewisburg to 138kV operation (circuit is built to 138kV). This will utilize part of the line already built to 138kV and will take place of the 3302 that currently feeds New Westville. The 3302 line will be retired as part of this project. - 6/1/2027 - $16.00M
- West Manchester Substation: The West Manchester Substation will be expanded to a double bus double breaker design where AES Ohio will install one 138kV circuit breaker, a 138/69kV transformer, and eight new 69kV circuit breakers. These improvements will improve help improve a non-standard bus arrangement where there is only one bus tie today and will improve the switching arrangement for the West Sonora Delivery Point. - 6/1/2027 - $9.90M

DL

- Install a series reactor on Cheswick-Springdale 138 kV line - 12/31/2024 - $9.00M
- Transmission Line Rearrangement:
  · Replacement of four structures and reconductor DLCO portion of Plum-Springdale 138 kV line.
  · Associated communication and relay setting changes at Plum and Cheswick. - 12/31/2024 - $15.00M

EKPC

- Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR. - 12/1/2026 - $8.50M
- Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR. - 12/1/2026 - $8.50M

PJM South

Dominion

- Reconductor approximately 10.5 miles of 115kV line #23 segment from Oak Ridge to AC2-079 Tap to minimum emergency ratings of 393 MVA Summer / 412 MVA Winter. - 6/1/2027 - $23.50M

Objective and Scope

The objectives of this assessment were as follows:

a) To identify system reinforcements as required to ensure compliance with NERC standards TPL-001-4.

b) To identify areas where the system as planned for the near term period 2022 through 2027 would not meet applicable reliability standards.

c) To develop and recommend preliminary facility expansion plans, including cost estimates and required in service dates, to ensure all areas meet applicable reliability criteria.

d) To identify areas where the system as planned for the longer term period 2028 through 2076 that would not meet applicable reliability criteria, and where appropriate, develop expansion plans. These plans include required in service dates of the facilities needed to bring those areas into compliance. This longer term planning is in consideration of larger scope projects that may require long lead time to implement.

e) To establish what will be included as baseline expansion costs for the allocation of the costs of expansion for those projects included in New Services Queues.

The scope of this assessment included analysis for the period 2022 through 2037 to ensure the system would meet all applicable reliability planning criteria. These assessments include baseline thermal, baseline voltage, thermal and voltage Load Deliverability, generation deliverability, and baseline stability analysis. The baseline thermal and voltage analysis encompasses an exhaustive analysis of all BES facilities for compliance with NERC P0 – P7 (TPL-001-4) events. In addition, consistent with NERC standard TPL-001-4, a number of extreme events as defined in Table 1 of TPL-001-4 were evaluated for risk and consequences to the system. Results of this study are not documented in this report due to their sensitive nature, and can be found in the 2022 Extreme Event Report.

The PJM Load Deliverability testing methods are described in Manual 14B, section 2. The tests ensure that an area of the transmission system that is experiencing higher than normal load levels (90/10) with higher than normal internal generation unavailability has the transmission capability to import energy to meet the transmission system reliability criteria. The generation deliverability testing ensures sufficient transmission capability so that generation can be ramped to full output so that excess energy can be exported to an area that is experiencing a capacity deficiency. PJM also performed a stability analysis consistent with NERC and local transmission owner criteria to ensure the system is stable for critical system conditions including fault conditions that include multi-phase faults and faults with delayed clearing and light load conditions.

Analytical testing is performed annually on a range of study years and system conditions to satisfy NERC standards. Every year analysis is performed on the 5 year out case, while the other nearer term cases (years 0 through 4) are retooled to be studied for specific projects as changes to system conditions warrant. Additional analysis is also performed for the longer term to identify marginal conditions that may require long lead time solutions. Currently as part of the RTEP a year 7 or year 8 case is studied in detail as part of the annual RTEP. During the 2022 RTEP, a year 7 (2028 study year) was studied.

PJM Generator Deliverability testing, which simulates higher than normal generation availability in an area, is performed at 50/50 load levels. PJM Load Deliverability testing, which is performed on 27 Locational Deliverability Areas (LDA's) within PJM's footprint, simulates an internal generation deficiency within the LDA (which simulates higher than expected forced outage conditions) being tested with the area at 90/10 load levels. Single and multiple contingency analyses were also performed on a shoulder peak case as described in subsequent sections of this document.

The combination of these tests includes simulation of various system conditions over a range of forecast system demands and generation availability scenarios that simulate planned and forced outage conditions. This analysis is performed for both the near term and longer term.

The continued need for the system reinforcements previously identified in prior RTEP Baseline Assessment Reports and the queue A through AE2 System Impact Studies associated with projects that have executed an Interconnection Service Agreement were evaluated. Any previously identified reinforcements that are no longer required were documented and removed from the list of RTEP Reinforcements. PJM adjusts required in-service dates based on updated forecasts that can affect the modeling of the system conditions. In the event that changing system conditions delay the need for a baseline upgrade beyond the 5 year planning horizon, PJM will re-evaluate the need for that upgrade. When evaluating the continued need for previous reinforcements, analysis is performed to test for system performance associated with all applicable reliability criteria including that specified under all event categories listed in Table 1 of TPL-001-4.

Analysis methodology

PJM completed a robust series of analysis over a broad spectrum of system conditions encompassing a range of study years and forecast demand levels. The following sections detail the assumptions of the modeling and analysis. The analysis sub-sections are grouped by the analysis type. The modeling assumptions of the 2027 cases and analysis are discussed in detail. The modeling assumptions for the retool cases are not discussed in detail but followed the same procedure as the 2027 case, which can be found in PJM Manual 14B, Attachment H The modeling assumptions of all of the cases follow the procedure in PJM Manual 14B, Attachment B. All study year cases model all normal (NERC TPL P0) operating procedures in place. PJM Manual 3 – Transmission Operations contains all PJM operating procedures that are applicable to PJM planning studies.

<table>
<tr><th>Analysis Type</th><th>NERC Contingency Category from Table 1 of TPL Standard</th><th>Applicable Limits Monitored</th><th>Monitored Elements</th><th>Contingencies Considered</th></tr>
<tr><td>normal system (no contingency)</td><td>P0</td><td rowspan="6">All System Operating Limits, including the most limiting thermal, voltage limit (magnitude and deviation), voltage collapse</td><td rowspan="8">All BES & select lower voltage facilities, all ties to neighboring systems regardless of voltage</td><td rowspan="8">Normal system, All BES & select lower voltage facilities. N-1-1 considers all possible combinations of single contingencies</td></tr>
<tr><td>single contingency</td><td>P1, P2</td></tr>
<tr><td>multiple contingency</td><td>P3, P4, P5, P6, P7</td></tr>
<tr><td>Load Deliverability</td><td>P1, P2</td></tr>
<tr><td>Light Load Reliability analysis</td><td>P0, P1, P2, P3, P4, P5, P6, P7</td></tr>
<tr><td>N-1-1 analysis</td><td>P3, P6</td></tr>
<tr><td>generation deliverability</td><td>P1, P2</td><td rowspan="2">thermal, voltage collapse</td></tr>
<tr><td>common mode outage procedure</td><td>P3, P4, P5, P6, P7</td></tr>
</table>

Table 3. **Analysis Type Summary**

Modeling Assumptions & Critical System Conditions

PJM selected a range of forecast demand levels for the year 2027.

- 2027 90/10 Summer Peak
- 2027 50/50 Summer Peak
- 2027 Light Load Reliability Analysis (50% of 50/50 Summer Peak)
- 2027 Winter Reliability Analysis

In addition to the analysis of the 2027 system, as part of this assessment, PJM also performed analysis of multiple critical system conditions in the near term and longer term planning horizons. The assessments of the critical system conditions within these study years will be discussed in subsequent sections of this document.

The load forecast from the 2027 PJM Load Forecast Report was used and can be found on the PJM website at the following address:

https://www.pjm.com/-/media/library/reports-notices/load-forecast/2021-load-report.ashx

The 2027 summer peak analysis used the 2027 summer model from the 2021 series MMWG (Multiregional Model Working Group) case. The model was updated according to the procedures in PJM Manual 14B, Attachment H. The case build is a collaborative process that involves PJM, PJM transmission owners, and neighboring entities. The case was reviewed with all PJM transmission owners to ensure that all existing and planned facilities were modeled. All future transmission upgrades with a required in-service date up to and including June 1, 2027 were modeled as in service. The list of future upgrades along with a schedule for implementation is contained in Appendix A.

All existing generation was modeled in the base case. Future generation that had an executed Interconnection Service Agreement (ISA) was modeled along with any upgrades required to maintain the reliability of the PJM system including the future generation. Future merchant transmission facilities that had an executed Interconnection Service Agreement (FSA) were modeled along with any upgrades required to maintain the reliability of the PJM system including the future merchant transmission. Information regarding all of these projects can be found on the PJM website at the address below.

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Adequate Reactive Power resources were included in the base model to ensure system voltage performance. Some of the reactive power resources modeled are existing and in-service equipment while some are planned with a future implementation date. A list of the planned reactive upgrades along with a schedule for implementation is contained in Appendix A. Table 4 below is a summary of the reactive power resources included in the 2027 case (note these are in addition to the reactive power associated with the generation noted above).

2027			
Area Name	Static	Dynamic	Total
AE	945	450	1395
AEP	14142	650	14792
AP	5817	1765	7582
BGE	9522	0	9522
CE	9798	1800	11598
DAY	1108	0	1108
DEO&K	842	0	842
DLCO	-110	0	-110
DP&L	1579	375	1954
DVP	10888	1750	12638
EKPC	1335	0	1335
FE	7229	1614	8843
JCPL	4762	40	4802
METED	1233	500	1733
PECO	5974	600	6574
PENELEC	2731	674	3405
PEPCO	1305	0	1305
PJM*	0	0	0
PPL	3259	0	3259
PSEG	7073	0	7073
RECO	0	0	0
UGI	66	0	66
Grand Total	89497	10218	99715

Table 4. **Reactive Power Resources in base case Static MVAR: Capacitor Banks, Switched Shunts; Dynamic MVAR: SVCs, Synchronous Condensers, and Dynamic Switched Shunts.**

The interchange targets in Table 5 below represents the net sum of all existing and planned yearly long-term firm transmission service commitments between PJM and neighboring systems for the 2027 summer period. A 2027, 2021 Series, MMWG case was used as a starting point for the modeling, all PJM firm transactions were included in the RTEP base case modeling. The base dispatch is set as defined in PJM Manual 14B, Attachment B.

2027 RTEP Interchange

Source	Sink	Total (MW)
PJM	NYISO	817
PJM	LGEE	-481
PJM	DEI	-156
PJM	WEC	94
PJM	LAGN	-100
PJM	CPLE	105
PJM	DUK	-100
PJM	TVA	400
PJM	EEI	0
PJM	AMIL	-884
PJM	OMUA	0
PJM	MEC	454
PJM	SMT	-285
Total		-136

Table 5. **Net Yearly Long Term Firm Interchange**

In all cases, where the physical design of connections or breaker arrangements resulted in the outage of more than the faulted facility when the fault was cleared, the additional facilities were also outaged in the load flow. That is, the breaker arrangements and system topology are used to develop and maintain the contingency files. For example, if a transformer is tapped off a line without a breaker, both the line and transformer were outaged as a single contingency event.

In addition, approved operating procedures were utilized as applicable. These operating procedures include the use of control devices such as Phase Angle Regulators (PARs) to manage flows on the system. Also, the expected operation of Remedial Action Schemes (RAS) were modeled and additionally tested where applicable. A complete listing of applicable remedial action schemes and operating procedures can be found in the Transmission Operation Manual (M-03) at the following link:

https://www.pjm.com/library/manuals.aspx

Contingencies Considered

The thermal and voltage analysis used a set of contingencies as required by NERC TPL standards. PJM's rationale was to define and select a comprehensive set that includes every possible BES contingency. Every possible single and multiple contingency loss of PJM BES elements is as described on Table 1 of NERC TPL standards was defined in contingency files and included in the assessment. No single or multiple BES contingencies were excluded from this assessment. The contingency set also included an inclusive set of single contingencies of non-BES elements that are modeled in the base case. A set of multiple facility contingencies involving non-BES facilities was included in the contingency set. A complete set of multiple facility contingencies involving non-BES facilities was not included in the contingency set given that issues on non-BES facilities are not expected to propagate to the BES system.

Contingency analysis takes into account the removal of all elements that the protection system and other automatic controls are expected to disconnect without operator intervention. This includes tripping of generators and transmission elements when protection equipment may exceed its performance capabilities.

In addition to the contingencies studied within PJM's footprint, analysis includes contingencies located in areas outside of PJM's footprint. PJM worked with its neighboring ISO's and RTO's to identify off-system contingencies that could affect PJM's system. All contingencies identified by these entities have been included in PJM's RTEP analysis.

- Over 14,000 Single contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- Over 18,000 Multiple Facility Contingencies were defined, including contingencies involving the loss of facilities in neighboring systems.
- The N-1-1 analysis considers every possible combination of single contingencies, a total of over 190,000,000 combinations.

PJM's 2022 analysis focused on contingencies as defined by TPL-001-4 Table 1 – Steady State & Stability Performance Planning Events.

Planned Outages in the Transmission Planning Horizon

Although there are situations in which outages are planned and scheduled more than 12 months in advance, more often outages are submitted no more than one year in advance of the planned outage. Most maintenance plans are developed, and therefore the associated outages are planned with less lead time. In cases where outages are scheduled less than one year out, the lead time makes it impractical for inclusion in planning studies under the TPL timeframe. Outages planned with a lead time of less than one year are evaluated by PJM Operations.

PJM performed additional analysis of planned maintenance outages in the planning horizon by studying certain combinations of scheduled maintenance outages as reported through PJM's eDART, outage coordination software used by PJM operations. To increase the conservatism of the simulation, planned outages of BES equipment were studied on a Summer Peak case, which reflects a higher load than the historical maintenance outage season, and therefore a more conservative test. PJM Planning notified PJM operations of the results of this analysis. The results of this analysis are documented in the PJM Maintenance Outage Analysis report, which is published annually. This report also includes the analysis of known outages of generation or Transmission Facilities with duration of at least six months.

Planned outages are typically not scheduled at peak demand levels. In addition to the targeted maintenance outage analysis described above, the deliverability tests are performed at peak demand levels, which produce more severe results and impacts than studies performed at off peak demand levels.

Monitored Facilities

All cases used for this assessment model all PJM Bulk Electric System facilities. The specific facilities monitored for each analysis is described in detail in subsequent sections of this document. PJM also monitored every tie line to neighboring systems regardless of voltage. Over 20,000 individually modeled BES facilities are monitored in the analysis that supports this assessment. In addition to all BES elements, PJM monitors lower voltage, non-BES, facilities that are monitored by PJM operations. As part of the 2022 RTEP, PJM expanded its monitored facility list to include BES facilities in the MISO footprint. PJM also completed several joint studies of neighboring systems as described in the scope contained in the Executive Summary above.

Analysis of Near-Term

As part of the near-term assessment, PJM evaluated a range of critical system conditions. The range of system conditions included thermal and voltage analysis of a 2027 90/10 summer peak scenario, thermal and voltage analysis of a 2027 50/50 summer peak scenario, and thermal and voltage analysis of a light load scenario. The thermal analysis included applicable thermal limit checking. The voltage limit analysis included checking applicable voltage magnitude and voltage drop limits. PV analysis is an important part of the RTEP analysis and is performed for selected scenarios. The methodology for selecting the PV scenarios is discussed in a subsequent section of this document.

Analysis is performed for planning events listed in Table 1 of TPL-001-4 to ensure that all performance requirements are met, or upgrades to the system are implemented to address required performance issues.

The forecast demand level, analysis type, and mapping to TPL standards are summarized in tables in this section. In addition, a summary of the analysis type, contingencies considered, monitored elements, and monitored limits are summarized in the Analysis Methodology Section. Stability tests are detailed in a subsequent section of this document.

Normal System (All Facilities in Service) Analysis

The 2027 90/10 summer peak, 50/50 summer peak, light load and shoulder peak cases were evaluated for system performance under normal conditions. These models use data consistent with information provided in MOD-032 and MOD-033 standards. The normal system analysis as defined in P0 on Table 1 of NERC TPL-001-4 does not include a contingency event. Rather, all facilities are assumed to be in-service. Every BES facility and select lower voltage facilities in PJM were monitored for thermal limits, voltage limits, and voltage stability. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Single Contingency Analysis

The 2027 50/50 summer peak, 90/10 summer peak and light load cases were evaluated for system performance following the loss of a single element. The single elements included all of the P1 and P2 events defined on Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage collapse. Additionally select off-system contingencies which may affect PJM's system were included in the single contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Contingency Analysis

The 2027 50/50 summer peak and light load cases were evaluated for system performance following the loss of two or more (multiple) elements. The multiple elements included all common mode events defined in Table 1 of NERC TPL-001-4. Every BES facility and select lower voltage facilities were monitored for thermal limits, voltage limits, and voltage stability. Additionally select off-system contingencies which may affect PJM's system were included in the Common Mode contingency analysis. Reinforcements were developed for areas where the system exceeded applicable thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

N-1-1 Analysis

The purpose of the N-1-1 analysis is to determine if all monitored facilities can be operated within normal thermal and voltage limits after an actual N-1 contingency and within the applicable emergency thermal and voltage limits after an additional simulated contingency. The 2027 50/50 summer peak was evaluated for system performance following a single contingency, followed by manual system adjustments, followed by another single contingency. The N-1-1 analysis monitored all BES facilities. The set of single contingencies that was used to compile the contingency pairs included all single contingencies in PJM regardless of voltage, all PJM tie lines regardless of voltage, and selected contingencies in neighboring systems. The contingency pairs that were considered included every possible combination of single contingencies, a total of over 376,000,000 combinations. The N-1-1 analysis also analyzed the contingency pairs in both possible orders to assess every combination and order of event. Reinforcements were developed for areas where the system failed to meet the applicable normal rating after the first contingency or the applicable emergency rating after the second contingency.

The N-1-1 analysis also assessed applicable voltage magnitude and voltage drop limits. For voltage magnitude and voltage drop testing, PJM screened for potential voltage violations. Voltage violations include exceeding the normal low voltage limit after the first contingency, emergency low limit after the second contingency, or exceeding the emergency voltage drop limit after the second contingency. Reinforcements were developed for areas where voltage violations were identified.

Deliverability Analysis

The 2027 base case was also used to analyze the capability of PJM's transmission system, including all PJM BES elements. To maintain reliability in a competitive capacity market, a resource must be deliverable to the overall network. PJM has developed the Load Deliverability and Generator Deliverability test methods for evaluating the adequacy of network capability for each of these deliverability requirements. Common mode outage analysis uses a procedure similar to Generator Deliverability to assess the impact of P3, P4, P5, P6 and P7 contingencies, as defined in PJM Manual 14B, Addendum 2.

A broad range of critical system conditions are established and analyzed through the deliverability test methods. The Generator Deliverability test establishes a critical stressed generation dispatch for every flowgate (monitored element and contingency pair) that could potentially be overloaded by the test. For every monitored facility, a critical stressed dispatch is created for all normal (all facilities in service) and single contingency conditions that could potentially overload the facility. This method results in the analysis of a large number of critical system conditions.

The load deliverability test procedure evaluates multiple critical system conditions though the evaluation of 27 individual stressed Locational Deliverability Areas, one thermal and one voltage case, for each of the defined Locational Deliverability Areas (LDA's) resulting in a minimum of 54 cases. The Locational Deliverability Areas are defined in Manual 14B – Attachment C. The load deliverability cases model stressed 90/10 summer peak loads in the LDA under study in each of the cases. A Capacity Emergency Transfer Objective (CETO) is identified. The CETO is the amount of energy an LDA will need to be able to import so that the area is not expected to have a loss of load event more frequently than one event in 25 years. A Capacity Emergency Transfer Limit (CETL) is calculated for each LDA (i.e. 54 cases) to determine the energy that can be imported into the area under test. In each case, the CETL ("the limit") is compared to the target Capacity Emergency Transfer Objective (CETO). Through this method, a large number of critical system conditions are also developed as part of the Load Deliverability Analysis. The system is planned to ensure that each of the LDAs meet the CETO at a minimum. System reinforcements were developed for any condition where the calculated import capability into any LDA would not meet the CETO.

Generator Deliverability Analysis

The PJM Generation Deliverability procedure was used to determine if the PJM transmission system, including all PJM BES elements, was adequate to deliver all PJM capacity resources to the network. Generator Deliverability analysis is performed to ensure that capacity resources within a given electrical area will, in aggregate, be able to be exported to other areas of PJM that are experiencing a capacity emergency. PJM utilizes the Generator Deliverability procedure to study the normal system and single contingencies under a stressed generation dispatch. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The Generator Deliverability procedure is defined in PJM Manual 14B Attachment C.

PJM performed the Generator Deliverability test on the 2027 50/50 summer peak model. The Generator Deliverability test examined system performance under normal and single contingency conditions. The contingency set included a complete set of single contingencies as defined by P1 and P2.1 in Table 1 of TPL-001-4.

The 2027 generator deliverability analysis tested a large number of critical system conditions. Every facility was monitored for applicable thermal limits for both the normal system and following the loss of every possible contingency. This process considers every one of the 19,000+ possible single contingencies for each monitored facility. As described in PJM Manual 14B, Attachment C a stressed dispatch was also developed and applied to each potentially overloaded flowgate to determine if an overload could be simulated. Through the method of applying a stressed dispatch to every possible single flowgate, the Generator Deliverability test identifies a large number of critical system conditions.

Reinforcements were developed for areas where the system failed to meet thermal limits or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Common Mode Outage Analysis

Common mode outage analysis procedures are similar to the generation deliverability analysis procedure; however this analysis focuses specifically on the loss of multiple elements. The common mode outage analysis studies all events listed as P4, P5 and P7 under a stressed generation dispatch. Over 15,000 multiple contingency events were analyzed. Every BES facility and select lower voltage facilities were monitored for thermal limits and voltage stability. The stressed generation dispatch is unique to each monitored element and contingency pair under study. The common mode outage procedure is defined in Addendum 2 of PJM Manual 14B.

Reinforcements were developed for areas where the system failed to meet thermal limits, voltage limits, or became unstable. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

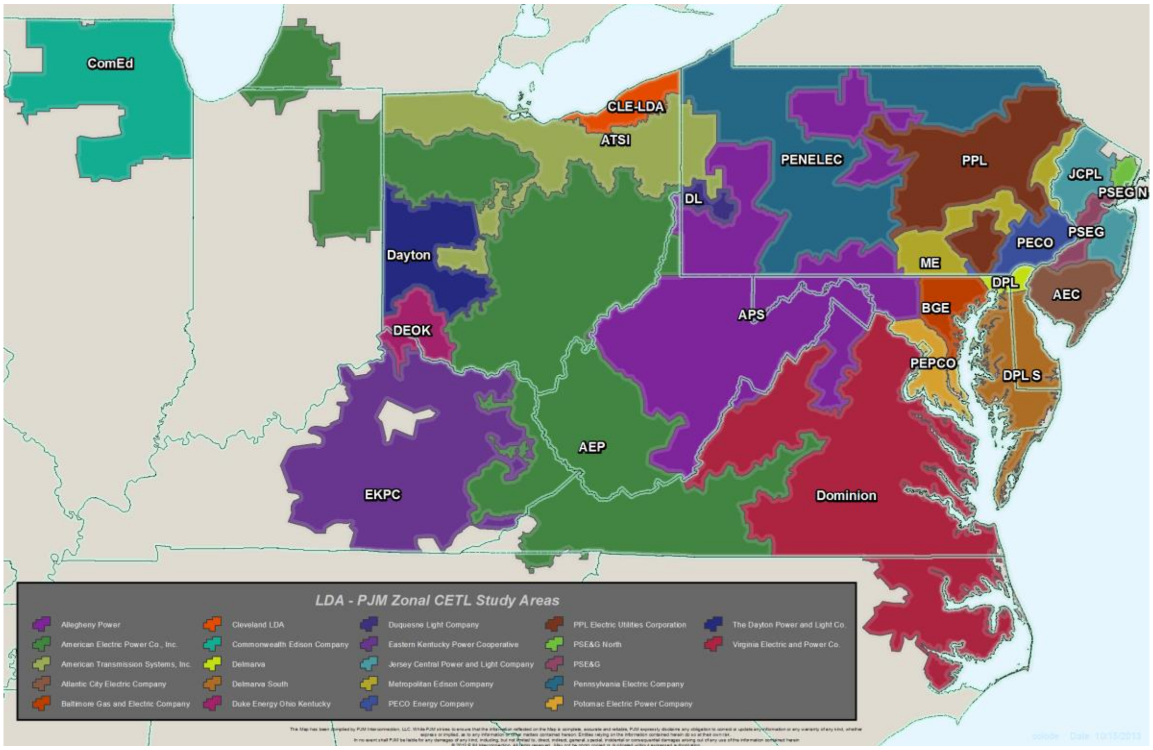
Load Deliverability Analysis

The Load Deliverability test procedures were used to determine if the Capacity Emergency Transfer Limit (CETL) for each of the various electrical areas of PJM is greater than each respective area's Capacity Emergency Transfer Objective (CETO).

There are currently 27 Locational Deliverability areas defined in PJM. The electrical areas within each of the 27 Locational Deliverability areas are described in table 6 and Map 2.

LDA	Description
EMAAC	Global area - PJM 500, JCPL, PECO, PSEG, AE, DPL, RECO
SWMAAC	Global area - BGE and PEPCO
MAAC	Global area - PJM 500, Penelec, Meted, JCPL, PPL, PECO, PSEG, BGE, Pepco, AE, DPL, UGI, RECO
PPL	PPL & UGI
PJM WEST	APS, AEP, Dayton, DUQ, ComEd, ATSI, DEO&K, EKPC, Cleveland, OVEC
WMAAC	PJM 500, Penelec, Meted, PPL, UGI
PENELEC	Pennsylvania Electric
METED	Metropolitan Edison
JCPL	Jersey Central Power and Light
PECO	PECO
PSEG	Public Service Electric and Gas
BGE	Baltimore Gas and Electric
PEPCO	Potomac Electric Power Company
AE	Atlantic City Electric
DPL	Delmarva Power and Light
DPLSOUTH	Southern Portion of DPL
PSNORTH	Northern Portion of PSEG
VAP	Dominion Virginia Power
APS	Allegheny Power
AEP	American Electric Power
DAYTON	Dayton Power and Light
DLCO	Duquesne Light Company
ComEd	Commonwealth Edison
ATSI	American Transmission Systems, Incorporated
DEO&K	Duke Energy Ohio and Kentucky
EKPC	Eastern Kentucky Power Cooperative
Cleveland	Cleveland Area

Table 6. **PJM Locational Deliverability Areas (LDA)**



Map 2. PJM Load Deliverability Areas

The 2027 Load Deliverability test used the 2027 summer peak base case as a starting point. From that starting point, 27 individual thermal Load Deliverability cases were built following the Load Deliverability thermal procedure as defined in PJM Manual 14B Attachment C. In addition, 27 individual voltage Load Deliverability cases were built following the Load Deliverability voltage procedure defined in PJM Manual 14B, Attachment C. This process developed one thermal and one voltage study case for each of the 27 Locational Deliverability Areas (LDA) resulting in 54 cases. These studies cover critical system conditions with load levels in the cases set to a 90/10 summer peak for the respective LDA under study and a 50/50 summer load level for all other areas. Modeling of specific system conditions such as load, reactive resources, and phase angle regulator settings were modeled as specified in PJM Manual 14B, Attachment G for the Load Deliverability tests. Manual 14B, Attachment C also specifies a procedure to dispatch generation in both the area assumed to be under a capacity emergency and the areas assumed not to be under a capacity emergency.

Capacity emergency transfer objectives (CETO's) for each of the 27 LDA's were used to set the target net interchange for the LDA under study in each of the thermal and voltage cases.

A thermal Load Deliverability study was then performed on each of the 27 thermal Load Deliverability cases. The thermal Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Reinforcements were developed for areas where the system failed to meet thermal limits. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

A voltage Load Deliverability study was then performed on each of the 27 voltage Load Deliverability cases. The voltage Load Deliverability study of each LDA monitored the respective LDA under study and tested system performance of the normal system and all single contingencies. Critical system conditions were analyzed and reinforcements were developed for areas where the system failed to meet voltage magnitude limits, voltage drop limits, or demonstrated a voltage collapse. The reinforcements, along with a schedule for implementation, are contained in the results section of this document.

Light Load Reliability Analysis

PJM also performed a year 2027 light load reliability analysis. The 50% of 50/50 summer peak demand level was chosen as being representative of a stressed light load condition. The system generating capability modeling assumption for this analysis is that the generation modeled reflects generation by fuel class that historically operates during the light load demand level. In addition to the generation dispatch, the Light Load Reliability Analysis procedure also requires that PJM set interchanges within PJM and neighboring regions to their historical values.

The starting point power flow is the same power flow case set up for the baseline analysis, with adjustment to the model for the light load demand level, interchange, and accompanying generation dispatch. The flowgates ultimately used in the light load reliability analysis were determined by running all contingencies maintained by PJM planning and monitoring all PJM market monitored facilities and all BES facilities. The contingencies used for light load reliability analysis included single and multiple contingencies, with the exception of the N-1-1criteria. Normal system conditions (P0) were also studied. All BES facilities and all non-BES facilities in the PJM real-time congestion management control facility list were monitored.

Winter Reliability Analysis

PJM also performed a year 2027 winter reliability analysis. This analysis included Generator Deliverability Studies, as well as Load Deliverability studies using a 2027 RTEP case with winter loadings and winter transmission line ratings. PJM focused these studies on Locational Deliverability Areas which had a Winter Loss of Load Expectation greater than 50%.

Voltage Stability

PV analysis was used to study a set of contingencies from the 2027 Load Deliverability voltage studies that were very severe or non-convergent. A set of single contingencies was selected for further study in the PV analysis. The methodology used to select the contingencies was to choose 500 kV or above contingencies that did not converge in a Load Deliverability voltage test. Also, contingencies that created a severe voltage drop or severe low magnitude violation on the BES were selected.

A PV analysis was then run on each of the selected contingencies. The analysis monitored all PJM facilities while simulating a transfer from all PJM generation outside the CETO area to all generation inside the CETO area where the contingency was identified. Typical to a PV analysis, the transfer was backed off until each contingency solved, and was then incrementally increased until a voltage collapse was simulated.

Retool Analysis of the Near-Term 2022-2027

Retool analysis is analysis that is performed during the current assessment to verify analysis that was performed in previous assessment. The retool analysis of the near-term was performed to verify the RTEP for the near-term due to forecasted changes in system conditions. Due to the recent overall net decrease in the projected load forecast for the PJM system, the retool work performed by PJM was a significant part of the 2022 RTEP. The retool analysis of the near-term included Generator Deliverability, Load Deliverability, common mode outage, and N-1-1 analysis. The methodologies for each of these analyses was performed as described in the detailed 2027 method descriptions in previous sections of this document. Through this approach, an extensive set of critical system conditions were analyzed. The conditions studies are summarized below.

Cases and contingency files for each year under study were updated in coordination with the Transmission Owners to reflect the most recent planned and existing facilities. The updated 2022 PJM load forecast was used to determine the load in the individual cases. The modeling updates included a review of the modeling of existing and planned facilities.

The retool analysis performed as part of the 2022 RTEP included the following groups of analysis. This analysis was in addition to the work performed as part of the near term and long term assessments required by the TPL standards. As a result of the significant generation deactivation notifications received throughout 2022, PJM performed a significant reliability review of years 2022 through 2027. As part of the 2022 RTEP, PJM performed system wide assessment of normal system, single contingency, multiple contingency, N-1-1, generator deliverability and load deliverability testing for year 2022 through 2027 summer peak models as needed for the widespread generation deactivations. PJM completed studies and developed system reinforcements related to generation deactivation requests for each year in the near-term in addition to the specific retool efforts outlined below. System enhancements, including an implementation schedule, were developed for every system performance issue that was identified as a result of the generation deactivation notifications. The system enhancements required as a result of the generation deactivations are described in more detail in the results section of this report. In addition to deactivation related retool studies PJM continually validates that previously identified system enhancements are still necessary.

2024 Retool

- B2003 verification (PSEG)

2025 Retool

- S2152 scope change (AEP)
- S2770 scope change (AEP)
- S2584 scope change (AEP)
- S1666 scope change (AEP)

2027 Retool

- Generation Updates Retool including New ISA, Withdrawn, Deactivation (Multiple TOs)

15 Year Planning and Analysis of the Longer-Term System

The purpose of the long term review is to simulate system trends to identify problems which may require longer lead time solutions. This enables PJM to take appropriate action when system issues may require initiation of a reinforcement project in anticipation of potential violations in the longer term. System issues uncovered that are amenable to shorter lead time remedies will be addressed as they enter into the near-term horizon. The detailed description of the 15 year planning process is described in PJM Manual 14B.

The 2022 RTEP also included a review of the fifteen year planning horizon through 2037. The analyses conducted as part of the review included normal system, single, and multiple (tower) contingency analysis of the 2027 50/50 Summer Peak case as summarized in Table 7. Following the 15 year procedure, the calculated loading on every flowgate was then scaled by a factor consistent with the forecasted load growth to determine a facility loading in years 2028 through 2037 (years 6 through 15). Both the Generator Deliverability and Load Deliverability procedures were used to establish the critical system conditions under which the system was evaluated.

Analysis Type	Monitored Flowgates	Contingencies Considered	Years Considered
Load Deliverability	Any BES element loaded at 75% or greater in the 2027 analysis	normal system, single, double circuit tower line	2028 through 2037
Generation Deliverability		normal system, single	

Table 7. **15 Year Planning Analysis**

Load forecasts for the years 2027 through 2037 from the 2021 PJM Load Forecast Report were used to generate load growth scaling factors for each of the highest loaded flowgates in each year. The DC scaling factors were then used to calculate a loading for each flowgate for each year 2028 through 2037.

Analysis of the Longer-Term System

PJM evaluated a 2028 (year 8) 50/50 Summer Peak case. One purpose of this evaluation was to identify any thermal or voltage reliability criteria violations in year 2028 that would require a longer term lead time to resolve. The evaluation of the 2028 Summer Peak case did not identify any reliability criteria violations that would require a longer lead time solution. In addition, this targeted analysis of 2028 summer conditions was benchmarked for consistency to the 2028 results from the 15 year analysis procedure.

Verification of Planned Reinforcements

Analysis was performed to verify that all planned reinforcements that were identified as part of the 2022 RTEP and all previously identified reinforcements acceptably resolved all criteria violations throughout the planning horizon. Analysis was also performed to verify that no new potential criteria violations were created as a result of implementing the required system reinforcements.

New Services Queue Analysis

Analysis for customer requests in the New Services Queue was performed for several different types of New Service Requests: Generator interconnection, long term firm transmission service, ARR requests, and Merchant transmission requests. The reliability of the requests is determined through two separate technical studies, the feasibility study and system impact study.

The feasibility study is the first study that is performed and is an initial look at the effect of the New Service Request on the transmission system. This study includes generator deliverability analysis that is performed on a summer peak load case to analyze the normal system and all single and multiple contingencies (Excluding N-1-1). Additionally Short Circuit analysis is performed.

If a developer elects to move forward and executes a System Impact Study Agreement PJM performs a more detailed study of the impact of the proposed request. The system impact study includes thermal analysis (AC Generator Deliverability) of the normal system and all single and multiple contingencies (Excluding N-1-1) as well as short circuit and stability assessments. Additionally, and as required based on the type of request made, load deliverability analysis may also be performed.

As part of the system impact study process, steady state voltage studies are performed for all interconnection projects. The steady state voltage studies included a check of the applicable voltage magnitude limits under normal and contingency conditions. The voltage of every BES facility was monitored. The contingencies included in the steady state voltage analysis included all multiple contingencies except N-1-1contingencies.

Specific results of interconnection studies can be found at:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

Short Circuit Assessment

PJM conducts short circuit analysis annually to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the system short circuit model with any planned generation and transmission facilities in service which could impact the study area. Short circuit analysis is performed consistent with the following industry standards:

1) ANSI/IEEE 551-2006 —IEEE Recommended Practice for Calculating Short-Circuit Currents in Industrial and Commercial Power Systems
   a) This standard is used to provide short circuit current information for breakers and power system equipment used to sense and interrupt fault currents.
2) ANSI/IEEE C37.04-1999 —IEEE Standard Rating Structure for AC High-Voltage Circuit Breakers

   a) This standard is used to establish the rating structure for circuit breakers and equipment associated with breakers.

3) ANSI/IEEE C37.010-1999 —IEEE Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Symmetrical Current Basis taking into consideration reclosing duration, X/R ratio differences, temperature conditions, etc.
4) ANSI/IEEE C37.5-1979 —IEEE Guide for Calculation of Fault Currents for Applications of AC High-Voltage Circuit Breakers Rated on a Total Current Basis
   a) This standard is used to calculate the fault current on breakers that are rated on a Total Current Basis.

Each of these standards is used jointly with transmission owners' methodologies as a basis to calculate fault currents on all BES breakers. By using these standards, single phase to ground and three phase fault currents are calculated and compared to the breaker interrupting capability, provided by the transmission owners, for each BES breaker within the PJM footprint. All breakers whose calculated fault currents exceed breaker interrupting capabilities are considered overdutied and reported to transmission owners for confirmation. All breakers are used in specific short circuit cases which help to identify the cause and year breakers are likely to become overdutied.

Short circuit cases are built consistent with a 2 year planning representation and a 5 year planning representation. The 2 year planning case consists of the current system in addition to all facilities planned to be in-service within the next year. The 5 year planning case uses the 2 year planning case as its base model and it is updated to include all system upgrades, generation projects, and merchant transmission projects planned to be in-service within 5 years. The 5 year planning case is similar to the 5 year PJM RTEP load flow basecase.

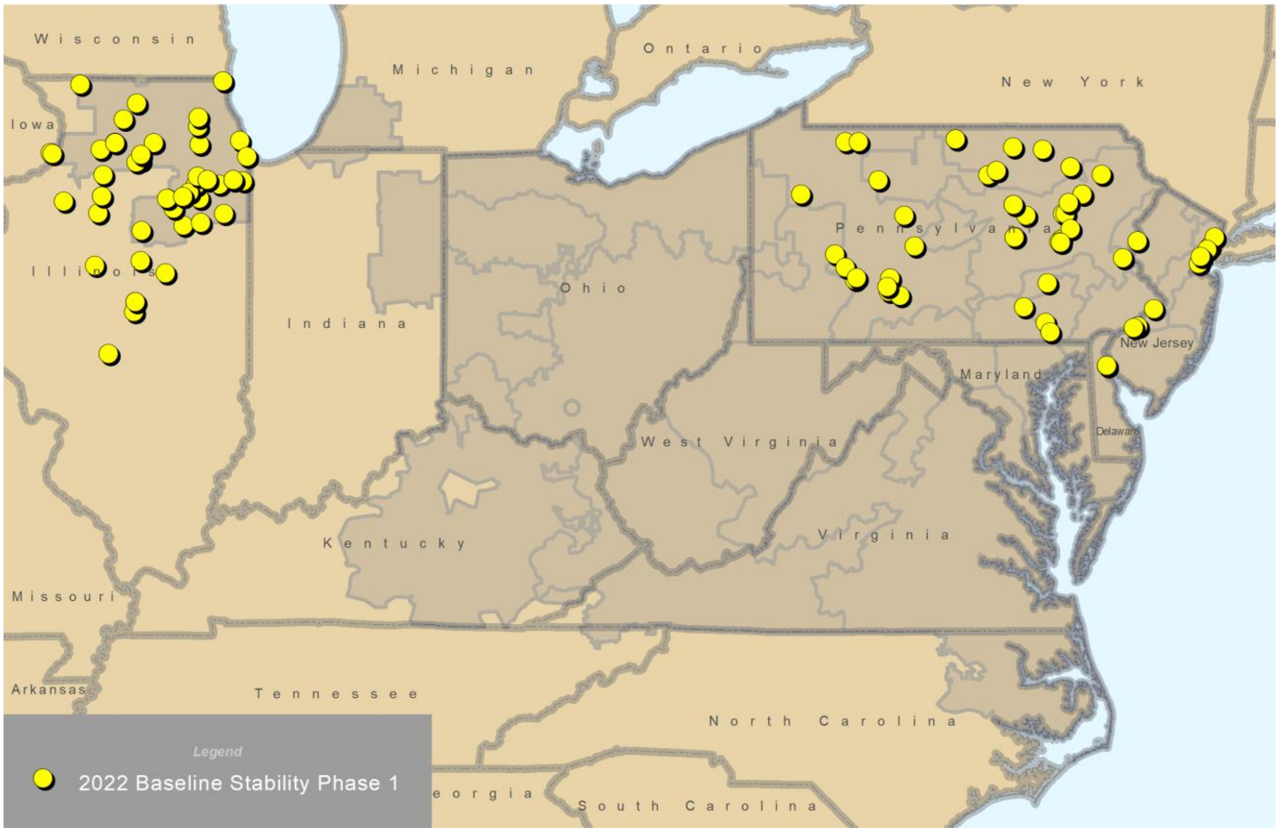
Once an overdutied breaker is confirmed breaker replacement and reinforcements along with cost estimates are determined. Breaker replacements and reinforcements, along with a schedule for implementation, were presented at monthly TEAC stakeholder meetings and are contained in the results section of this document.

Stability Assessment

PJM performs multiple tiers of analysis to ensure the system will remain stable and have satisfactory dynamic performance for disturbances that are consistent with Table 1 of the NERC TPL-001-4 standards. Collectively, the studies performed assess system dynamic performance over a wide range of load levels. Whenever system dynamic performance does not meet criteria, appropriate reinforcements are incorporated in the system plans and design. These measures include the installation of PSS (Power System Stabilizer), Excitation system refinements, dynamic or static reactive supports for wind generation plants, relaying and breaker configuration modifications.

Stability Studies	2022 RTEP
Annual baseline stability analysis of 1/3 of existing stations	100
New Services Queue stability analysis	119
Total	**219**

Table 8. **Number of Generation Stations Studied for Stability as Part of the 2022 RTEP**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Michigan
Ontario
New York
Iowa
Pennsylvania
Illinois
Indiana
Ohio
New Jersey
Maryland
Delaware
West Virginia
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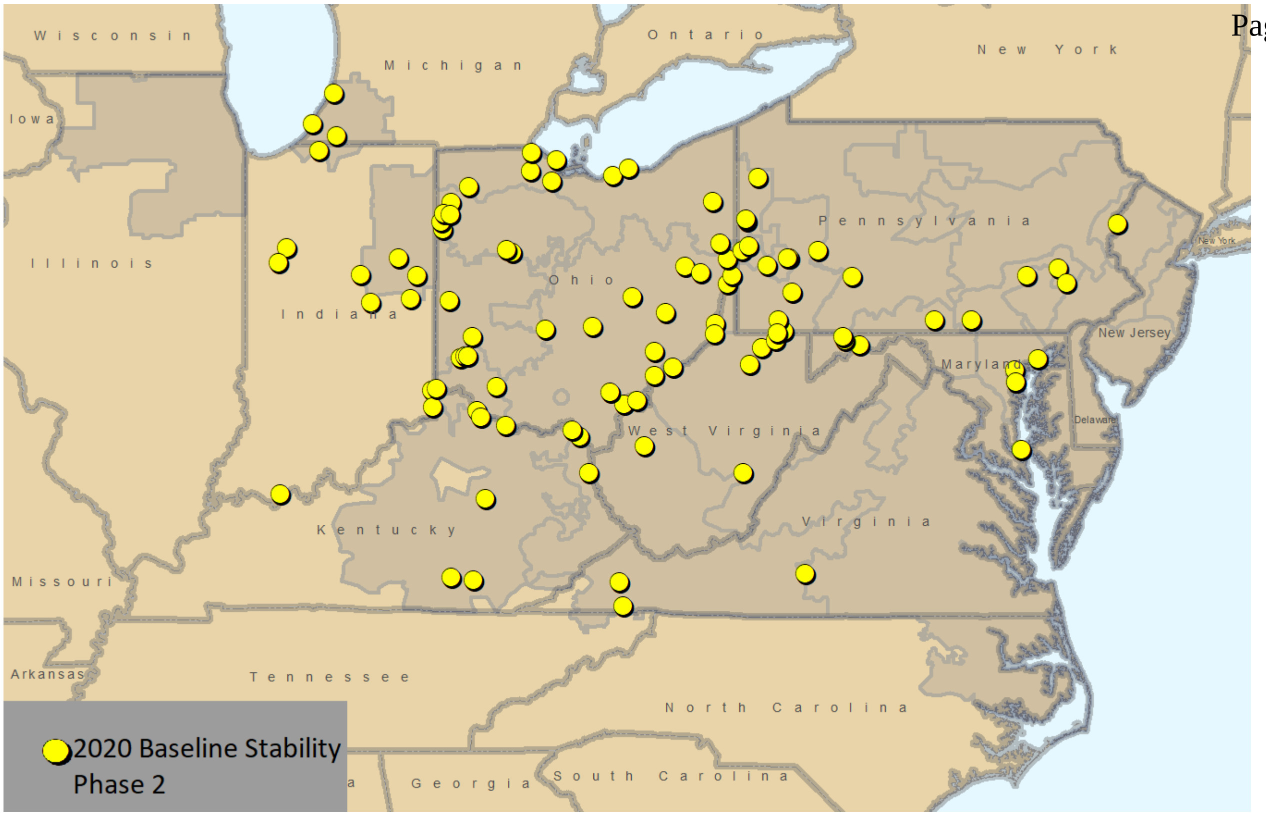
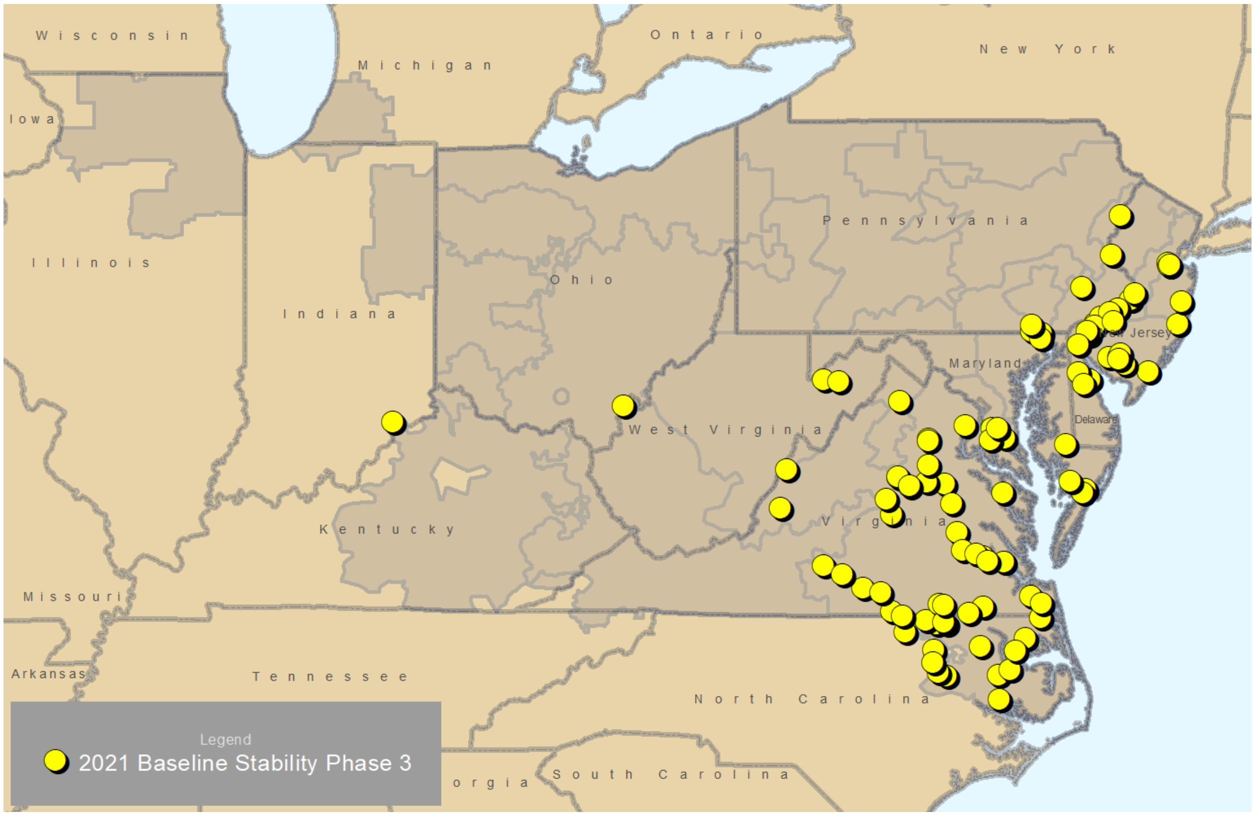
2022 Baseline Stability Phase 1
eorgia
South Carolina





Map 3. Three-Year Baseline Stability Cycle

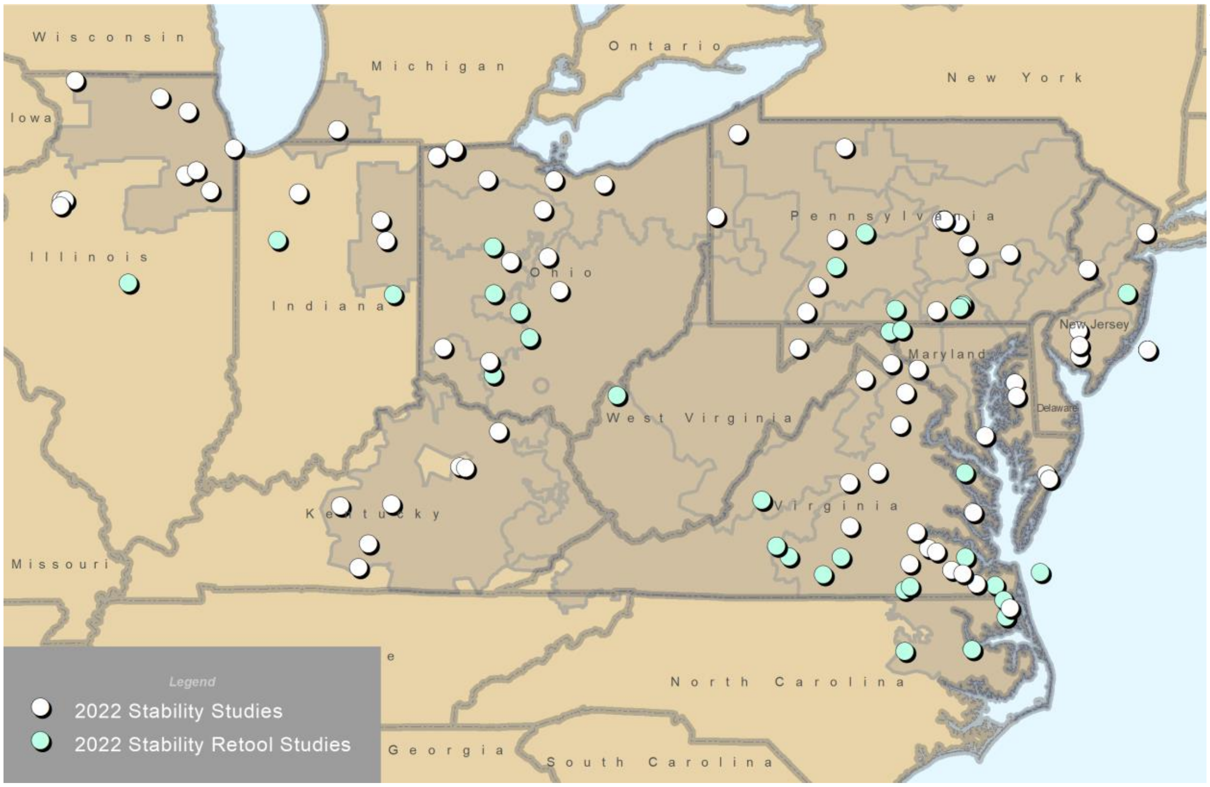
Good engineering practices as related to ensuring adequate system dynamic performance for the Bulk Electric System starts with proper base case models. PJM uses full ERAG MMWG models as a starting point for the dynamic stability analysis. All known transmission system as well as generation model changes available from approved system plans are incorporated. Step response simulations are conducted to detect and correct any modeling errors. Case initialization results are carefully analyzed to make sure that all the initial conditions are satisfactory. A 20 second no fault simulation is performed to ensure proper parameters are used in the models.

As part of the 2022 RTEP, several tiers of system stability analysis were performed. The first tier of this analysis includes PJM's annual comprehensive transient stability assessment of generating stations in the system. The annual analysis is performed for one third of the PJM footprint each year.

The annual baseline analysis includes an evaluation of the system under light load conditions as well as peak load conditions. PJM's rationale for choosing a light load case is that the light load system conditions are found to be the most challenging and severe from a transient stability perspective. The analysis also includes an evaluation of the system under summer peak loading (50/50) conditions.

PJM incorporates dynamic load models in peak load stability study to consider the behaviors of dynamic loads including induction motor loads. Various contingencies near load centers and generation stations are studied to ensure PJM system meets dynamic voltage recovery criteria as well as transient stability and damping criteria. In addition PJM evaluates the impact of dynamic load models on the system performance under a stressed power transfer condition across PJM eastern interface.

All PJM stability studies start by testing the system for a major transmission line switching operation. This examines the system under system normal conditions, as specified in TPL-001-4. The system response is verified by monitoring generating unit angle curves over a 20 second time frame. This test also provides the information to verify that all dynamic parameters are correctly initiating and responding properly. The stability test procedure includes a simulation of all applicable disturbances on all outlets of generating plants for multiple contingency (P3-P7) conditions. Additionally, all existing Remedial Action Schemes and their controlling actions are evaluated to ensure their effectiveness. A visual depiction of the coverage of the three latest baseline stability study cycles is shown in Map 3 above.



Map 4. Locations of proposed generation studied for stability in 2022

A second tier of PJM's stability assessment includes stability analysis for all proposed generator interconnections that exceed 20 MWs. New generator interconnections represent a significant modification to the system that could affect stability. In 2022 as part of the generation interconnection process, PJM completed transient stability analysis for 119 proposed generator interconnections within the PJM footprint. The locations of these proposed generators are shown in Map 4. In this analysis P0, P1, P2, P3, P4, P5, P6 and P7 conditions were analyzed for disturbances on all generating plant outlets as well as on transmission lines at a minimum, one bus away and more than one bus away from the point of interconnection if warranted by the system topology. In general, the analysis associated with proposed generation additions identifies any potential transient stability concerns among the generators electrically close to the portion of the system being modified. The proposed generation interconnections span all transmission system voltage levels and are widespread throughout PJM's footprint. Hence, the resulting stability analysis covers broad sections of PJM's Bulk Electric System. Solutions to the identified problems are developed and implemented prior to the proposed generation being placed in service.

As depicted in Map 4, the locations of the proposed generation additions are dispersed throughout the PJM footprint. In addition to monitoring the stability of the proposed generation, existing generation within several layers of the interconnection bus are also monitored. The transient stability analysis that is run for proposed generation interconnections not only ensures that the proposed unit will remain stable but also ensures that the transient stability of existing generation at nearby buses will not be compromised. It is important to note that the relative queue position is respected for this analysis, so that potential transient stability concerns are identified for the proposed unit and nearby existing generation. This ensures that violations will be allocated to the correct project based on queue order. The results of this analysis and any required upgrades or other mitigation measures needed, are identified in the System Impact Study for each New Service Request and are posted on the PJM web at the following address:

https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

A third tier of PJM's stability analysis includes ad-hoc studies that were performed in 2022 and occur annually to support PJM operations.

The transient stability analysis performed by PJM is done with forward looking cases representing the system as planned in future years. Given the continued load growth within the PJM footprint and the on-going transmission system reinforcements that are identified as part of the regional transmission expansion plan, the transient stability of the system is expected to continue to improve.

As a result of PJM integrating each of these tiers of stability assessment, PJM has ensured its compliance to all applicable standards including the assessments required by Table 1 of the NERC TPL001-4 standard.

Based on PJM's knowledge and evaluation of current and forecasted system conditions, stability related upgrades would not require a lead time during the longer-term (year 6 and beyond) time frame, therefore stability analysis is not performed beyond 5 years out.

N-1-1 Stability Assessment

N-1-1 stability study for 75 plants was performed in 2022 RTEP. Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. PJM will continue to conduct N-1-1 stability study for selected plants on a rotating basis.

Critical contingency pairs which may lead to potential stability issues were applied to the study. RAS or specific operation guidelines were also implemented if necessary. Comprehensive time-domain simulations for N-1-1 contingencies were conducted to ensure those plants comply with PJM stability criteria. No transient stability issues and damping violations were identified during the study.

NPIR Plant Specific Stability & Voltage Assessment

PJM has a total of 17 plants that fit the criteria for NPIR stability study. All 17 of those plants were studied as part of the 2022 RTEP. PJM will continue to study these 17 plants annually as part of future RTEPs. RAS or specific operation guidelines were implemented if necessary. Also, several nuclear plant NPIR studies were performed to verify and validate 2022 new dynamic models per TOs request.

In addition to the NPIR stability studied, PJM also performed NPIR voltage studies. As part of the 2022 RTEP, all 17 PJM nuclear plants were studied to ensure these plants comply with voltage monitoring criteria. Voltage magnitude and voltage drop were monitored under selected contingencies. Study results have been sent to NGOs.

Results of 2022 RTEP

The results of the baseline assessment for the 2022 – 2037 periods are presented below. This report, containing all corrective reinforcements, is provided to applicable regional entities annually in compliance with TPL-001-4. All of the upgrades below were presented to the TEAC stakeholder committee at one of the monthly TEAC stakeholder meetings in 2022.

PJM found the following areas of the PJM system to not meet reliability criteria during the assessment of the 2022 – 2037 study periods. These baseline upgrades were all identified as part of the 2022 RTEP. The list of required upgrades contains a summary of the system deficiencies and the associated action needed to achieve required system performance. This includes deficiencies identified in multiple sensitivity studies. The expected required in-service date of each upgrade is also included. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. System enhancements and corrective action plans are reviewed in subsequent annual studies for continued validity and implementation status of identified system facilities and operating procedures. Additionally, results include all recommended upgrades where short circuit analysis shows that existing breakers exceed their equipment rating.

Upgrades identified and established in previous RTEP cycles are detailed in Appendix A.

The most up to date information concerning in-service dates and schedule for implementation can be found at the following link: https://www.pjm.com/planning/project-construction.aspx. With the exception of the baseline upgrades noted below, all other areas of the system were found to meet applicable reliability criteria.

1) Baseline Upgrade b3130.11
- Overview of Reliability Problem
  - Criteria Violation: Five Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace four Atlantic 34.5 kV breakers (BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment
  - Upgrade In-Service Date: 9/30/2023
  - Estimated Upgrade Cost: $3.50M
  - Construction Responsibility: JCPL

2) Baseline Upgrade b3130.12
- Overview of Reliability Problem
  - Criteria Violation: Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) overduties
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and

associated equipment.

- Upgrade In-Service Date: 6/1/2024
- Estimated Upgrade Cost: $4.20M
- Construction Responsibility: JCPL

3) Baseline Upgrade b3350.1

- Overview of Reliability Problem
  - Criteria Violation: Bellefonte 69kV breakers JJ, C, I, AB, Z and G are overdutied.
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace overdutied 69 kV breakers C, G, I, Z, AB and JJ in place. The new 69 kV breakers to be rated at 3000 A 40 kA breakers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: AEP

4) Baseline Upgrade b3350.2

- Overview of Reliability Problem
  - Criteria Violation: Bellefonte 69kV breakers JJ, C, I, AB, Z and G are overdutied.
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade remote end relaying at Point Pleasant, Coalton and South Point 69 kV substations.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

5) Baseline Upgrade b3354

- Overview of Reliability Problem
  - Criteria Violation: 40 kV circuit breakers '42' and '43' at Bexley station are exceeding their maximum fault interuption rating (132% and 138%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers '42' and '43' at Bexley station with 3000 A, 40 kA 69 kV breakers (operated at 40 kV), slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $1.00M
  - Construction Responsibility: AEP

6) Baseline Upgrade b3355

- Overview of Reliability Problem
  - Criteria Violation: 34.5 kV circuit breakers 'A' and 'B' at South Side Lima station are

exceeding their maximum fault interuption rating (106% and 112%).

- Criteria Test: AEP 715 criteria

- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers 'A' and 'B' at South Side Lima station with 1200 A, 25 kA 34.5 kV breakers, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.75M
  - Construction Responsibility: AEP

7) Baseline Upgrade b3356

- Overview of Reliability Problem
  - Criteria Violation: 69 kV circuit breaker 'H' at West End Fostoria station is exceeding its maximum fault interuption rating (102%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breaker 'H' at West End Fostoria station with 3000 A, 40 kA 69 kV breaker, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEP

8) Baseline Upgrade b3357

- Overview of Reliability Problem
  - Criteria Violation: 69 kV circuit breakers 'C', 'E', and 'L' at Natrium station are exceeding their maximum fault interuption rating (104% , 110%,and 104%).
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Replace circuit breakers 'C', 'E,' and 'L' at Natrium station with 3000 A, 40 kA 69 kV breakers, slab, control cables and jumpers.
  - Upgrade In-Service Date: 6/1/2023
  - Estimated Upgrade Cost: $1.50M
  - Construction Responsibility: AEP

9) Baseline Upgrade b3701

- Overview of Reliability Problem
  - Criteria Violation: Congestion
  - Criteria Test: Market Efficiency
- Overview of Reliability Solution
  - Description of Upgrade: Replace terminal equipment on the French's Mill-Junction JST1 138 kV line.
  - Upgrade In-Service Date: 11/1/2022
  - Estimated Upgrade Cost: $0.77M

- Construction Responsibility: APS

10) Baseline Upgrade b3703

- Overview of Reliability Problem
  - Criteria Violation: Load loss for the loss of the two source to West Windsor
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a third 69 kV supply line from Penns Neck substation to the West Windsor substation.
  - Upgrade In-Service Date: 1/1/2023
  - Estimated Upgrade Cost: $1.05M
  - Construction Responsibility: PSEG

11) Baseline Upgrade b3704

- Overview of Reliability Problem
  - Criteria Violation: Transformer End of Life
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger capacity transformer with load tap changer (LTC) and new dead tank circuit breaker. Install a new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment to complete the bay within the Lawrence 230 kV switchyard
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $13.36M
  - Construction Responsibility: PSEG

12) Baseline Upgrade b3705

- Overview of Reliability Problem
  - Criteria Violation: Transformer End of Life
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Replace existing 230/138 kV Athenia No. 220-1 transformer.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $13.04M
  - Construction Responsibility: PSEG

13) Baseline Upgrade b3706

- Overview of Reliability Problem
  - Criteria Violation: Transformer End of Life
  - Criteria Test:
- Overview of Reliability Solution

- Description of Upgrade: Replace Fair Lawn 230/138kV transformer No. 220-1 with an existing O&M system spare at Burlington.
- Upgrade In-Service Date: 6/1/2026
- Estimated Upgrade Cost: $4.45M
- Construction Responsibility: PSEG

14) Baseline Upgrade b3707.1

- Overview of Reliability Problem
  - Criteria Violation: Thermal Violation
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor approximately 0.57mi of 115kV Line #1021 from Harmony Village to Greys Point with 768 ACSS to achieve a summer emergency rating of 237MVA. The current conductor is 477 ACSR.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $1.89M
  - Construction Responsibility: Dominion

15) Baseline Upgrade b3707.2

- Overview of Reliability Problem
  - Criteria Violation: Thermal Violation
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor approximately 0.97mi of 115 kV Line #65 from Rappahanock to White Stone with 768 ACSS to achieve a summer emergency rating of 237MVA. The current conductor is 477 ACSR.
  - Upgrade In-Service Date: 6/1/2022
  - Estimated Upgrade Cost: $1.89M
  - Construction Responsibility: Dominion

16) Baseline Upgrade b3708

- Overview of Reliability Problem
  - Criteria Violation: Light Load Overlplad on the Shawville 230/115/17.2 kV transformer #2A
  - Criteria Test: Generation Deliverability and N-1
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Shawville 230/115/17.2 kV transformer with a new Shawville 230/115 kV transformer and associated facilities. Replace the plant's No. 2B 115/17.2 kV transformer with a larger 230/17.2 kV transformer.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $8.78M
  - Construction Responsibility: PENELEC

17) Baseline Upgrade b3709

- Overview of Reliability Problem
  - Criteria Violation: Summer Shade-West Columbia 69 kV line section is overloaded
  - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Summer Shade-West Columbia 69 kV 0.19 miles of 266 conductor double circuit to 556 conductor.
  - Upgrade In-Service Date: 12/1/2025
  - Estimated Upgrade Cost: $0.19M
  - Construction Responsibility: EKPC

18) Baseline Upgrade b3710

- Overview of Reliability Problem
  - Criteria Violation: AA2-161 to Yukon two 138 kV lines
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Scope Change: During 2027 RTEP analysis, it was determined that the topology change caused the new AA2-161 to Charleroi line to be overloaded. The new overload is conductor limited and the cost to upgrade 12.8 miles is $32 M. As a result, the cost-effective solution is to alternatively reconductor Yukon to AA2-161 ckt 1 & 2 while maintaining the existing topology. The cost to upgrade is $10.64 M Expand the future AA2-161 138 kV six (6) breaker ring bus into an eleven (11) breaker substation with a breaker-and-a-half layout by constructing five (5) additional breakers and expanding the bus. Loop the Yukon - Charleroi #2 138 kV line into the future AA2-161 substation. Relocate terminals as necessary at AA2-161. Upgrade terminal equipment (wavetrap, substation conductor) and relays at Yukon, Huntingdon, Springdale, Charleroi, and the AA2-161 substation.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $10.64M
  - Construction Responsibility: APS

19) Baseline Upgrade b3711

- Overview of Reliability Problem
  - Criteria Violation: The Dresden 345/138 kV No. 81 transformer is overloaded
  - Criteria Test: Winter Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Install 345 kV bus tie 5-20 circuit breaker in the ring at Dresden station in series with existing bus tie 5-6.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $4.26M
  - Construction Responsibility: ComEd

20) Baseline Upgrade b3712

- Overview of Reliability Problem
    - Criteria Violation: Low voltage at Broughtentown, Tommy Gooch and Highland 69 kV
    - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
    - Description of Upgrade: Install a 28 MVAR cap bank at Liberty Junction 69 kV.
    - Upgrade In-Service Date: 12/1/2022
    - Estimated Upgrade Cost: $0.54M
    - Construction Responsibility: EKPC

21) Baseline Upgrade b3713

- Overview of Reliability Problem
    - Criteria Violation: Not Specified
    - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
    - Description of Upgrade: • Disconnect and remove five 138 kV bus tie lines and associated equipment from the Avon Lake Substation to the plant (800-B Bank, 8-AV-T Generator, 5-AV-T, 6-AV-T, and 7-AV-T).
      • Disconnect and remove one 345 kV bus tie line and associated equipment from the Avon substation to the plant (Unit 9).
      • Adjust relay settings at Avon Lake, Avon and Avondale substations.
      • Removal/rerouting of fiber to the plant and install new fiber between the 345 kV and 138 kV yards for the Q4-AV-BUS relaying.
      • Remove SCADA RTU, communications and associated equipment from plant.
    - Upgrade In-Service Date: 4/28/2023
    - Estimated Upgrade Cost: $2.50M
    - Construction Responsibility: ATSI

22) Baseline Upgrade b3714

- Overview of Reliability Problem
    - Criteria Violation: Overload Beaver to Hayes 345KV Line
    - Criteria Test: Gen Deliv - SP
- Overview of Reliability Solution
    - Description of Upgrade: • Replace (4) 345 kV disconnect switches (D74, D92, D93, & D116) with 3000 A disconnect switches at Beaver.
      • Replace dual 954 45/7 ACSR SCCIR conductors between 5” pipe and WT with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver.
      • Replace 3000 SAC TL drop and 3000 SAC SCCIR between 954 ACSR and 5” bus with new, which meets or exceeds ratings of SN: 1542 MVA, SSTE: 1878 MVA at Beaver.
      • Upgrade BDD relays at breaker B-88 and B-115 at Beaver.
      • Relay settings changes at Hayes.
    - Upgrade In-Service Date: 6/1/2023
    - Estimated Upgrade Cost: $2.10M
    - Construction Responsibility: ATSI

23) Baseline Upgrade b3715.1

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: At the existing PPL Williams Grove substation, install a new 300 MVA 230/115 kV transformer.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $6.30M
  - Construction Responsibility: PPL

24) Baseline Upgrade b3715.2

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new ~3.4 mile 115 kV single circuit transmission line from Williams Grove to Allen substation.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $5.11M
  - Construction Responsibility: PPL

25) Baseline Upgrade b3715.3

- Overview of Reliability Problem
  - Criteria Violation: 2021 Window 1: N2-SVM8, N2-SVM9, N2-SVM10, N2-SVM11, N2-SVM12, N2-SVM13, N2-SVM16, N2-SVM17, N2-SVM18, N2-SVM19, N2-SVM26, N2-SVM27, N2-SVD1, N2-SVD2, N2-SVD3, N2-SVD4, N2-SVD5, N2-SVD6, N2-SVD7, N2-SVD8, N2-SVD9, N2-SVD10, N2-SVD11, N2-SVD12, N2-SVD15, N2-SVD16
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Install a new Allen four breaker ring bus switchyard near the existing MetEd Allen substation on adjacent property presently owned by FirstEnergy. Terminate the Round Top-Allen and the Allen-PPGI (PPG Industries) 115 kV lines into the new switchyard.
  - Upgrade In-Service Date: 6/1/2026
  - Estimated Upgrade Cost: $6.41M
  - Construction Responsibility: ME

26) Baseline Upgrade b3716

- Overview of Reliability Problem
  - Criteria Violation: Load loss for the loss of the two source to the Customer
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: Construct a third 69kV supply line from Totowa substation to the customer's substation
  - Upgrade In-Service Date: 1/1/2025
  - Estimated Upgrade Cost: $8.20M
  - Construction Responsibility: PSEG

27) Baseline Upgrade b3717.1

- Overview of Reliability Problem
  - Criteria Violation: Overload Collier - Erwin #1 and #2 138KV Lines, Forbes - Oakland 138KV Line, Carson - Oakland 138KV Line
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
  - Description of Upgrade: Install a series reactor on Cheswick-Springdale 138 kV line
  - Upgrade In-Service Date: 12/31/2024
  - Estimated Upgrade Cost: $9.00M
  - Construction Responsibility: DL

28) Baseline Upgrade b3717.2

- Overview of Reliability Problem
  - Criteria Violation: Overload Collier - Erwin #1 and #2 138KV Lines, Forbes - Oakland 138KV Line, Carson - Oakland 138KV Line
  - Criteria Test: N-1-1 Thermal
- Overview of Reliability Solution
  - Description of Upgrade: Transmission Line Rearrangement:
    · Replacement of four structures and reconductor DLCO portion of Plum-Springdale 138 kV line.
    · Associated communication and relay setting changes at Plum and Cheswick.
  - Upgrade In-Service Date: 12/31/2024
  - Estimated Upgrade Cost: $15.00M
  - Construction Responsibility: DL

29) Baseline Upgrade b3718.1

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution

- Description of Upgrade: Install one 500/230kV 1440MVA transformer at a new substation called Wishing Star. Cut and extend 500 kV Line #546 (Brambleton-Mosby) and 500 kV Line #590 (Brambleton-Mosby) to the proposed Wishing Star substation. Lines to terminate in a 500 kV breaker and a half configuration.
- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: Dominion

30) Baseline Upgrade b3718.10

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #9349 (Sojourner-Mars)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~1.61 miles of 230 kV line #9349 (Sojourner-Mars) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

31) Baseline Upgrade b3718.11

- Overview of Reliability Problem
  - Criteria Violation: Overduty Breakers
  - Criteria Test: GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade 4-500 kV breakers (total) to 63kA on either end of 500 kV Line #502 (Loudoun-Mosby)
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

32) Baseline Upgrade b3718.12

- Overview of Reliability Problem
  - Criteria Violation: Overduty Breakers
  - Criteria Test: GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade 4-500 kV breakers (total) to 63 kA on either end of 500 kV Line #584 (Loudoun-Mosby)
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

33) Baseline Upgrade b3718.13

- Overview of Reliability Problem
  - Criteria Violation: >300 MW load loss
  - Criteria Test: N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Cut and loop 230 kV Line #2079 (Sterling Park-Dranesville) into Davis Drive substation and install two GIS 230 kV breakers.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

34) Baseline Upgrade b3718.14

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 230 kV transmission line for ~3.5 miles along with substation upgrades at Wishing Star and Mars. New right-of-way will be needed and will share same structures with the 500 kV line. New conductor to have a minimum summer normal rating of 1573 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

35) Baseline Upgrade b3718.2

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Install one 500/230 kV 1440 MVA transformer at a new substation called Mars near Dulles International Airport.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

36) Baseline Upgrade b3718.3

- Overview of Reliability Problem
  - Criteria Violation: Multiple overloads in the Data Center Alley area
  - Criteria Test: N-1 & N-1-1 Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 500 kV transmission line for ~ 3.5 miles along with substation upgrades at Wishing Star and Mars. New right-of-way will be needed and will share same structures with the line. New conductor to have a

minimum summer normal rating of 4357 MVA.

- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: Dominion

37) Baseline Upgrade b3718.4

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2214 (Buttermilk-Roundtable)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~0.62 miles of 230 kV line #2214 (Buttermilk-Roundtable) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

38) Baseline Upgrade b3718.5

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2031 (Enterprise-Greenway-Roundtable)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~1.52 miles of 230 kV line #2031 (Enterprise-Greenway-Roundtable) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

39) Baseline Upgrade b3718.6

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2186 (Enterprise-Shellhorn)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~0.64 miles of 230 kV line #2186 (Enterprise-Shellhorn) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

40) Baseline Upgrade b3718.7

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2188 (Lockridge-Greenway-Shellhorn)

- Criteria Test: N-1, GenDeliv Summer 2025

- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~2.17 miles of 230 kV line #2188 (Lockridge-Greenway-Shellhorn) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

41) Baseline Upgrade b3718.8

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2223 (Lockridge-Roundtable)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~0.84 miles of 230 kV line #2223 (Lockridge-Roundtable) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

42) Baseline Upgrade b3718.9

- Overview of Reliability Problem
  - Criteria Violation: Overload of 230 kV line #2218 (Sojourner-Runway-Shellhorn)
  - Criteria Test: N-1, GenDeliv Summer 2025
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor ~3.98 miles of 230 kV line #2218 (Sojourner-Runway-Shellhorn) to achieve a summer rating of 1574 MVA.
  - Upgrade In-Service Date: 6/1/2025
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: Dominion

43) Baseline Upgrade b3719

- Overview of Reliability Problem
  - Criteria Violation: Spare equipment for Bergen series reactors (R and M), and short circuit issue on the Bergen bypass switches
  - Criteria Test: Spare equipment
- Overview of Reliability Solution
  - Description of Upgrade: Replace the two existing 1200A Bergen 138 kV Circuit Switchers with two (2) 138 kV Disconnect Switches to achieve a minimum summer normal device rating of 298 MVA and a minimum summer emergency rating of 454 MVA.
  - Upgrade In-Service Date: 12/31/2022
  - Estimated Upgrade Cost: $1.20M

- Construction Responsibility: PSEG

44) Baseline Upgrade b3720

- Overview of Reliability Problem
  - Criteria Violation: The Abbe-Johnson 69 kV Line overload to 102.6% of its 92MVA/SE for P2-1 Contingecy, opening the Abbe-Johnson #1 69 kV Line breaker B-177 at Johnson
  - Criteria Test: Baseline Analysis
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the Abbe-Johnson #2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. Replace three disconnect switches (A17, D15 & D16) and line drops and revise relay settings at Abbe. Replace one disconnect switch (A159) and line drops and revise relay settings at Johnson. Replace two MOAB disconnect switches (A4 & A5), one disconnect switch (D9), and line drops at Redman.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.90M
  - Construction Responsibility: ATSI

45) Baseline Upgrade b3721

- Overview of Reliability Problem
  - Criteria Violation: The Avery-Hayes 138 kV line overloads to 103.65% of its 282MVA/SE rating for P7 Contingecy, Outage of the Beaver-Hayes & Beaver-AD1-103 345 kV Lines
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.40M
  - Construction Responsibility: ATSI

46) Baseline Upgrade b3722

- Overview of Reliability Problem
  - Criteria Violation: the Darrah – Barnett 69 kV line is overloaded
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the existing Darrah-Barnett 69 kV line, approximately 2.8 miles and replace a riser at Darrah station.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $6.98M
  - Construction Responsibility: AEP

47) Baseline Upgrade b3723

- Overview of Reliability Problem

- Criteria Violation: the George Washington-Kammer 138 kV line is overloaded
- Criteria Test: Summer Gen Deliv

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the George Washington – Kammer 138 kV circuit, except for 0.1-mile of previously-upgraded T-line outside each terminal station (6.7 miles of total upgrade scope). Remove the existing 6-wired steel lattice towers and supplement the right-of-way as needed.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $18.30M
  - Construction Responsibility: AEP

48) Baseline Upgrade b3724

- Overview of Reliability Problem
  - Criteria Violation: overload of Cloverdale-Ingersoll Rand-Monterey Avenue 69 kV line sections
  - Criteria Test: AEP 715 criteria
- Overview of Reliability Solution
  - Description of Upgrade: Install 138 kV circuit switcher on the high-side of Transformer #2 at Roanoke station (previously proposed as a portion of s2469.7, posted in 2021 AEP local plan).
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.10M
  - Construction Responsibility: AEP

49) Baseline Upgrade b3725

- Overview of Reliability Problem
  - Criteria Violation: The Elwood-Goodings Grove 345 kV line is overloaded
  - Criteria Test: Winter Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace the 1600A bus disconnect switch at Goodings Grove on L11622 Elwood-Goodings Grove 345 kV.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: ComEd

50) Baseline Upgrade b3726

- Overview of Reliability Problem
  - Criteria Violation: Voltage Drop violations at Black Oak 500 kV substation
  - Criteria Test: N-1-1 Summer and Winter
- Overview of Reliability Solution
  - Description of Upgrade: Install two new 500 kV breakers on the existing open SVC string to create a new bay position. Relocate & Reterminate facilities as necessary to

move the 500 kV SVC into the new bay position and Install a 500 kV breaker on the 500/138 kV #3 transformer. Upgrade relaying at Black Oak substation.

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $17.37M
- Construction Responsibility: APS

51) Baseline Upgrade b3727

- Overview of Reliability Problem
  - Criteria Violation: The Fawkes-Duncannon Lane Tap 69 kV line (LGEE-EKPC tie line) is overloaded
  - Criteria Test: Winter N-1, EKPC 715 Criteria
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $8.50M
  - Construction Responsibility: EKPC

52) Baseline Upgrade b3728.1

- Overview of Reliability Problem
  - Criteria Violation: Overload on Peach Bottom - Conastone 500 kV for several contingencies
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade two Breaker bushings on the 500 kV Line 5012 (Conastone-Peach Bottom) at Conastone substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: BGE

53) Baseline Upgrade b3728.2

- Overview of Reliability Problem
  - Criteria Violation: Overload on Peach Bottom - Conastone 500 kV for several contingencies
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace 4 meters and bus work inside Peach Bottom substation on the 500 kV Line 5012 (Conastone-Peach Bottom).
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $3.80M
  - Construction Responsibility: PECO

54) Baseline Upgrade b3729

- Overview of Reliability Problem
  - Criteria Violation: Overload Conowingo – Colora 230 kV kV circuit
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: To increase the Maximum Operating Temperature of DPL Circuit 22088 (Colora-Conowingo 230 kV), install cable shunts on each phase, on each side of four (4) dead-end structures and replace existing insulator bells.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.26M
  - Construction Responsibility: DPL

55) Baseline Upgrade b3730

- Overview of Reliability Problem
  - Criteria Violation: Overload on Lackawanna 500/230 kV transformer # T3
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.70M
  - Construction Responsibility: PPL

56) Baseline Upgrade b3731

- Overview of Reliability Problem
  - Criteria Violation: 40 kV circuit breaker 'J' at McComb station was identified as being overdutied.
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Replace 40kV breaker J at McComb station with a new 3000A 40kA breaker
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEP

57) Baseline Upgrade b3732

- Overview of Reliability Problem
  - Criteria Violation: e, low voltage and voltage-drop violations on the 34.5kV system between North Coshocton, Newcomerstown, and West New Philly stations, including Allegheny Pipe, East Coshocton, Gen Tire, Isleta, Morgan Run, North Coshocton, Newcomerstown, W Lafayette, Copper head 34.5kV buses
  - Criteria Test: AEP 715 critiera

- Overview of Reliability Solution
  - Description of Upgrade: Install a 6 MVAR, 34.5kV cap bank at Morgan Run station
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.37M
  - Construction Responsibility: AEP

58) Baseline Upgrade b3733

- Overview of Reliability Problem
  - Criteria Violation: The Summerhill-Willow Grove Switch 69kV line segment is overloaded
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the 1.8 mile 69kV T-line between Summerhill and Willow Grove Switch. Replace 4/0 ACSR conductor with 556 ACSR.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $5.10M
  - Construction Responsibility: AEP

59) Baseline Upgrade b3734

- Overview of Reliability Problem
  - Criteria Violation: voltage-drop violations at Rarden switch, Otway station, Tick Ridge station, and Rarden station 69kV buses
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Install a 7.7 MVAR, 69kV cap bank at both Otway station and Rosemount station
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.73M
  - Construction Responsibility: AEP

60) Baseline Upgrade b3735

- Overview of Reliability Problem
  - Criteria Violation: Thermal overload on theArrowhead - Hillman Highway 69 kV line; Voltage Mag and Voltage Drop Violations at Arrowhead, Damascus,Hillman and South Abington 69kV buses
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Terminate the existing Broadford – Wolf Hills #1 138 kV line into Abingdon 138 kV Station. This line currently bypasses the existing Abingdon 138 kV Station; Install two new 138 kV circuit breakers on each new line exit towards Broadford and towards Wolf Hills #1; Install one new 138 kV circuit breaker on line exit towards South Abingdon for standard bus sectionalizing

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $8.48M
- Construction Responsibility: AEP

61) Baseline Upgrade b3736.1

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Establish 69kV bus and new 69 kV line CB at Dorton substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $1.13M
  - Construction Responsibility: AEP

62) Baseline Upgrade b3736.10

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Henry Clay S.S Retirement:
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.30M
  - Construction Responsibility: AEP

63) Baseline Upgrade b3736.11

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Cedar Creek substation work
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.44M
  - Construction Responsibility: AEP

64) Baseline Upgrade b3736.12

- Overview of Reliability Problem

  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Breaks substation retire 46kV equipment:
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.25M
  - Construction Responsibility: AEP

65) Baseline Upgrade b3736.13

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Pike 29 SS and Rob Fork SS
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.42M
  - Construction Responsibility: AEP

66) Baseline Upgrade b3736.14

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Serve Pike 29 and Rob Fork customers from nearby 34kV Distribution sources.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

67) Baseline Upgrade b3736.15

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution

- Description of Upgrade: Poor Bottom substation install
- Upgrade In-Service Date: 12/1/2027
- Estimated Upgrade Cost: $0.00M
- Construction Responsibility: AEP

68) Baseline Upgrade b3736.16

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Henry Clay 46kV substation retirement
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

69) Baseline Upgrade b3736.17

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: New Draffin 69kV substation install
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

70) Baseline Upgrade b3736.18

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Draffin 46kV substation retirement
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.00M
  - Construction Responsibility: AEP

71) Baseline Upgrade b3736.2

- Overview of Reliability Problem
    - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: At Breaks substation, reuse 72kV breaker A as the new 69kV line breaker.
    - Upgrade In-Service Date: 12/1/2027
    - Estimated Upgrade Cost: $0.71M
    - Construction Responsibility: AEP

72) Baseline Upgrade b3736.3

- Overview of Reliability Problem
    - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV
    - Upgrade In-Service Date: 12/1/2027
    - Estimated Upgrade Cost: $58.52M
    - Construction Responsibility: AEP

73) Baseline Upgrade b3736.4

- Overview of Reliability Problem
    - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
    - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
    - Description of Upgrade: Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit.
    - Upgrade In-Service Date: 12/1/2027
    - Estimated Upgrade Cost: $11.15M
    - Construction Responsibility: AEP

74) Baseline Upgrade b3736.5

- Overview of Reliability Problem
    - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
    - Criteria Test: AEP 715 critiera

- Overview of Reliability Solution
  - Description of Upgrade: Retire ~ 6.2 mi Henry Clay – Elwood 46kV line section.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $4.30M
  - Construction Responsibility: AEP

75) Baseline Upgrade b3736.6

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7 mi double circuit extension to Poor Bottom 69kV.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $3.42M
  - Construction Responsibility: AEP

76) Baseline Upgrade b3736.7

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Retire Draffin substation and replace with a new substation. Install a new 0.25 mi double circuit extension to New Draffin substation.
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $2.01M
  - Construction Responsibility: AEP

77) Baseline Upgrade b3736.8

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Remote End work at Jenkins substation
  - Upgrade In-Service Date: 12/1/2027

- Estimated Upgrade Cost: $0.03M
- Construction Responsibility: AEP

78) Baseline Upgrade b3736.9

- Overview of Reliability Problem
  - Criteria Violation: Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations
  - Criteria Test: AEP 715 critiera
- Overview of Reliability Solution
  - Description of Upgrade: Provide Transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations
  - Upgrade In-Service Date: 12/1/2027
  - Estimated Upgrade Cost: $0.41M
  - Construction Responsibility: AEP

79) Baseline Upgrade b3737.1

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation – Reconfigure substation.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.24M
  - Construction Responsibility: JCPL

80) Baseline Upgrade b3737.10

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Atlantic 230 kV substation – Convert to double-breaker double-bus.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $31.47M
  - Construction Responsibility: JCPL

81) Baseline Upgrade b3737.11

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A

- Overview of Reliability Solution
  - Description of Upgrade: Freneau substation – Update relay settings on the Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

82) Baseline Upgrade b3737.12

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Smithburg substation – Update relay settings on the Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

83) Baseline Upgrade b3737.13

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Oceanview substation – Update relay settings on the Atlantic 230 kV lines.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.04M
  - Construction Responsibility: JCPL

84) Baseline Upgrade b3737.14

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Red Bank substation – Update relay settings on the Atlantic 230 kV lines.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.04M
  - Construction Responsibility: JCPL

85) Baseline Upgrade b3737.15

- Overview of Reliability Problem

- Criteria Violation: N/A
- Criteria Test: N/A

- Overview of Reliability Solution
  - Description of Upgrade: South River substation – Update relay settings on the Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

86) Baseline Upgrade b3737.16

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation – Update relay settings on the Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

87) Baseline Upgrade b3737.17

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Atlantic substation – Construct a new 230 kV line terminal position to accept the generator lead line from the offshore wind Larrabee Collector station.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $4.95M
  - Construction Responsibility: JCPL

88) Baseline Upgrade b3737.18

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: G1021 (Atlantic-Smithburg) 230 kV upgrade.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $9.68M

- Construction Responsibility: JCPL

89) Baseline Upgrade b3737.19

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: R1032 (Atlantic-Larrabee) 230 kV upgrade.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $14.50M
  - Construction Responsibility: JCPL

90) Baseline Upgrade b3737.2

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation – 230 kV equipment for direct connection.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.77M
  - Construction Responsibility: JCPL

91) Baseline Upgrade b3737.20

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: New Larrabee Collector station-Atlantic 230 kV line.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $17.07M
  - Construction Responsibility: JCPL

92) Baseline Upgrade b3737.21

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee-Oceanview 230 kV line upgrade.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $6.00M

- Construction Responsibility: JCPL

93) Baseline Upgrade b3737.22

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Construct the Larrabee Collector station AC switchyard, composed of a 230 kV 3 x breaker and a half substation with a nominal current rating of 4000 A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. Procure land adjacent to the AC switchyard, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $121.10M
  - Construction Responsibility: MAOD

94) Baseline Upgrade b3737.23

- Overview of Reliability Problem
  - Criteria Violation: The Richmond-Waneeta 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the underground portion of Richmond-Waneeta 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $16.00M
  - Construction Responsibility: AEC

95) Baseline Upgrade b3737.24

- Overview of Reliability Problem
  - Criteria Violation: The Cardiff-Lewis 138 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Cardiff-Lewis 138 kV by replacing 1590 kcmil strand bus inside Lewis substation.
  - Upgrade In-Service Date: 4/30/2028
  - Estimated Upgrade Cost: $0.10M
  - Construction Responsibility: AEC

96) Baseline Upgrade b3737.25

- Overview of Reliability Problem

- Criteria Violation: The Lewis No. 2-Lewis No. 1 138 kV line is overloaded
- Criteria Test: Summer Generator Deiverability

- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Lewis No. 2-Lewis No. 1 138 kV by replacing its bus tie with 2000 A circuit breaker.
  - Upgrade In-Service Date: 4/30/2028
  - Estimated Upgrade Cost: $0.50M
  - Construction Responsibility: AEC

97) Baseline Upgrade b3737.26

- Overview of Reliability Problem
  - Criteria Violation: The Cardiff-New Freedom 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Cardiff-New Freedom 230 kV by modifying existing relay setting to increase relay limit.
  - Upgrade In-Service Date: 4/30/2028
  - Estimated Upgrade Cost: $0.30M
  - Construction Responsibility: AEC

98) Baseline Upgrade b3737.27

- Overview of Reliability Problem
  - Criteria Violation: The Clarksville-Lawrence 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild approximately 0.8 miles of the D1018 (Clarksville-Lawrence 230 kV) line between Lawrence substation (PSEG) and structure No. 63.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $11.45M
  - Construction Responsibility: JCPL

99) Baseline Upgrade b3737.28

- Overview of Reliability Problem
  - Criteria Violation: The Kilmer I-Lake Nelson I 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Kilmer I-Lake Nelson I 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.42M
  - Construction Responsibility: JCPL

100) Baseline Upgrade b3737.29

- Overview of Reliability Problem
  - Criteria Violation: Smithburg-Windsor 230 kV, Smithburg-Deans 500 kV lines and Smithburg 500/230 kV No. 2 transformer are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $206.48M
  - Construction Responsibility: JCPL

101) Baseline Upgrade b3737.3

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Lakewood Generator substation – Update relay settings on the Larrabee 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.03M
  - Construction Responsibility: JCPL

102) Baseline Upgrade b3737.30

- Overview of Reliability Problem
  - Criteria Violation: The Smithburg 500/230 kV No. 1 transformer is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Add third Smithburg 500/230 kV transformer.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $13.40M
  - Construction Responsibility: JCPL

103) Baseline Upgrade b3737.31

- Overview of Reliability Problem
  - Criteria Violation: The Lake Nelson I-Middlesex 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Additional reconductoring required for Lake Nelson I-Middlesex 230 kV.
  - Upgrade In-Service Date: 6/1/2029

- Estimated Upgrade Cost: $3.30M
- Construction Responsibility: JCPL

104) Baseline Upgrade b3737.32

- Overview of Reliability Problem
  - Criteria Violation: The Larrabee-Smithburg No. 1 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild Larrabee-Smithburg No. 1 230 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $44.77M
  - Construction Responsibility: JCPL

105) Baseline Upgrade b3737.33

- Overview of Reliability Problem
  - Criteria Violation: The Red Oak A-Raritan River 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Red Oak A-Raritan River 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $11.05M
  - Construction Responsibility: JCPL

106) Baseline Upgrade b3737.34

- Overview of Reliability Problem
  - Criteria Violation: The Red Oak B-Raritan River 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor Red Oak B-Raritan River 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $3.90M
  - Construction Responsibility: JCPL

107) Baseline Upgrade b3737.35

- Overview of Reliability Problem
  - Criteria Violation: The Raritan River-Kilmer I 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor small section of Raritan River-Kilmer I 230 kV.
  - Upgrade In-Service Date: 6/1/2029

- Estimated Upgrade Cost: $0.20M
- Construction Responsibility: JCPL

108) Baseline Upgrade b3737.36

- Overview of Reliability Problem
  - Criteria Violation: The Raritan River-Kilmer W 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace substation conductor at Kilmer and reconductor Raritan River-Kilmer W 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $25.88M
  - Construction Responsibility: JCPL

109) Baseline Upgrade b3737.37

- Overview of Reliability Problem
  - Criteria Violation: The Hope Creek-LS Power Cable Ease 230 kV No. 1 and No. 2 and LS Power Cable East-LS Power Silver Run 230 kV lines are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Add a third set of submarine cables, rerate the overhead segment, and upgrade terminal equipment to achieve a higher rating for the Silver Run-Hope Creek 230 kV line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $61.20M
  - Construction Responsibility: LS POWER

110) Baseline Upgrade b3737.38

- Overview of Reliability Problem
  - Criteria Violation: The Linden-Tosco 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Linden subproject: Install a new 345/230 kV transformer at the Linden 345 kV Switching station, and relocate the Linden-Tosco 230 kV (B-2254) line from the Linden 230 kV to the existing 345/230 kV transformer at Linden 345 kV.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $24.92M
  - Construction Responsibility: PSEG

111) Baseline Upgrade b3737.39

- Overview of Reliability Problem
  - Criteria Violation: The Linden-Tosco 230 kV line is overloaded

- Criteria Test: Summer Generator Deiverability

- Overview of Reliability Solution
  - Description of Upgrade: Bergen subproject: Upgrade the Bergen 138 kV ring bus by installing a 80 kA breaker along with the foundation, piles, and relays to the existing ring bus, install breaker isolation switches on existing foundations and modify and extend bus work.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $5.53M
  - Construction Responsibility: PSEG

112) Baseline Upgrade b3737.4

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: B54 Larrabee-South Lockwood 34.5 kV line transfer.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.31M
  - Construction Responsibility: JCPL

113) Baseline Upgrade b3737.40

- Overview of Reliability Problem
  - Criteria Violation: The Windsor-Clarksville 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Windsor to Clarksville subproject: Create a paired conductor path between Clarksville 230 kV and JCPL Windsor Switch 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $4.28M
  - Construction Responsibility: JCPL

114) Baseline Upgrade b3737.41

- Overview of Reliability Problem
  - Criteria Violation: The Windsor-Clarksville 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Windsor to Clarksville subproject: Upgrade all terminal equipment at Windsor 230 kV and Clarksville 230 kV as necessary to create a paired conductor path between Clarksville and JCPL East Windsor Switch 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.49M

- Construction Responsibility: PSEG

115) Baseline Upgrade b3737.42

- Overview of Reliability Problem
  - Criteria Violation: The Kilmer-Lake Nelson I 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade inside plant equipment at Lake Nelson I 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $3.80M
  - Construction Responsibility: PSEG

116) Baseline Upgrade b3737.43

- Overview of Reliability Problem
  - Criteria Violation: The Kilmer-Lake Nelson W 230 kV line is overloaded
  - Criteria Test: Summer Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Kilmer W-Lake Nelson W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.16M
  - Construction Responsibility: PSEG

117) Baseline Upgrade b3737.44

- Overview of Reliability Problem
  - Criteria Violation: The Lake Nelson-Middlesex-Greenbrook W 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Lake Nelson-Middlesex-Greenbrook W 230 kV line drop and strain bus connections at Lake Nelson 230 kV.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $0.12M
  - Construction Responsibility: PSEG

118) Baseline Upgrade b3737.45

- Overview of Reliability Problem
  - Criteria Violation: The Gilbert-Springfield 230 kV line is overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor 0.33 miles of PPL’s portion of the Gilbert-Springfield 230 kV line.

- Upgrade In-Service Date: 6/1/2030
- Estimated Upgrade Cost: $0.38M
- Construction Responsibility: PPL

119) Baseline Upgrade b3737.46

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Install a new breaker at Graceton 230 kV substation to terminate a new 230 kV line from the new greenfield North Delta station
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.55M
  - Construction Responsibility: BGE

120) Baseline Upgrade b3737.47

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Build a new greenfield North Delta station with two 500/230 kV 1500 MVA transformers and nine 63 kA breakers (four high side and five low side breakers in ring bus configuration).
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $76.27M
  - Construction Responsibility: Transource

121) Baseline Upgrade b3737.48

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for PECO's portion of the line rebuild which is 4.1 miles.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $18.82M

- Construction Responsibility: PECO

122) Baseline Upgrade b3737.49

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Bring the Cooper-Graceton 230 kV line “in and out” of North Delta by constructing a new double-circuit North Delta-Graceton 230 kV (0.3 miles) and a new North Delta-Cooper 230 kV (0.4 miles) cut-in lines.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.56M
  - Construction Responsibility: PECO

123) Baseline Upgrade b3737.5

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee Collector station-Larrabee 230 kV new line.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $7.52M
  - Construction Responsibility: JCPL

124) Baseline Upgrade b3737.50

- Overview of Reliability Problem
  - Criteria Violation: The Peach Bottom-Conastone 500 kV, Peach Bottom-Furnace Run 500 kV, Furnace Run-Conastone 230 kV No. 1 and 2 lines and Furnace Run 500/230 kV No. 1 and 2 transformers are overloaded
  - Criteria Test: Winter Generator Deiverability
- Overview of Reliability Solution
  - Description of Upgrade: Bring the Peach Bottom-Delta Power Plant 500 kV line “in and out” of North Delta by constructing a new Peach Bottom-North Delta 500 kV (0.3 miles) cut-in and cut-out lines.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.56M
  - Construction Responsibility: PECO

125) Baseline Upgrade b3737.51

- Overview of Reliability Problem
  - Criteria Violation: Four Peach Bottom circuit breakers "205", "235", "225" and "255" are

overdutied

- Criteria Test: Short Circuit

- Overview of Reliability Solution
  - Description of Upgrade: Replace four 63 kA circuit breakers "205," "235," "225" and "255" at Peach Bottom 500 kV with 80 kA.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $5.60M
  - Construction Responsibility: PECO

126) Baseline Upgrade b3737.52

- Overview of Reliability Problem
  - Criteria Violation: One Conastone circuit breakers "B4" is overdutied
  - Criteria Test: Short Circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace one 63 kA circuit breaker "B4" at Conastone 230 kV with 80 kA.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $1.30M
  - Construction Responsibility: BGE

127) Baseline Upgrade b3737.56

- Overview of Reliability Problem
  - Criteria Violation:
  - Criteria Test:
- Overview of Reliability Solution
  - Description of Upgrade: Build a new North Delta-Graceton 230 kV line by rebuilding 6.26 miles of the existing Cooper-Graceton 230 kV line to double circuit. Cooper-Graceton is jointly owned by PECO & BGE. This subproject is for BGE's portion of the line rebuild which is 2.16 miles.
  - Upgrade In-Service Date: 6/1/2029
  - Estimated Upgrade Cost: $9.92M
  - Construction Responsibility: BGE

128) Baseline Upgrade b3737.6

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee Collector station-Smithburg No. 1 500 kV line (new asset). New 500 kV line will be built double circuit to accommodate a 500 kV line and a 230 kV line.
  - Upgrade In-Service Date: 12/31/2027

- Estimated Upgrade Cost: $150.35M
- Construction Responsibility: JCPL

129) Baseline Upgrade b3737.7

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild G1021 Atlantic-Smithburg 230 kV line between the Larrabee and Smithburg substations as a double circuit 500 kV/230 kV line.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $62.85M
  - Construction Responsibility: JCPL

130) Baseline Upgrade b3737.8

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Smithburg substation 500 kV expansion to 4-breaker ring.
  - Upgrade In-Service Date: 12/31/2027
  - Estimated Upgrade Cost: $68.25M
  - Construction Responsibility: JCPL

131) Baseline Upgrade b3737.9

- Overview of Reliability Problem
  - Criteria Violation: N/A
  - Criteria Test: N/A
- Overview of Reliability Solution
  - Description of Upgrade: Larrabee substation upgrades.
  - Upgrade In-Service Date: 6/1/2030
  - Estimated Upgrade Cost: $0.86M
  - Construction Responsibility: JCPL

132) Baseline Upgrade b3738

- Overview of Reliability Problem
  - Criteria Violation: Charleroi - Dry Run
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Charleroi - Dry Run 138 kV Line: Replace Limiting Terminal Equipment

  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.38M
  - Construction Responsibility: APS

133) Baseline Upgrade b3739

- Overview of Reliability Problem
  - Criteria Violation: Dry Run - Mitchell
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Dry Run - Mitchell 138 kV Line: Replace Limiting Terminal Equipment
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.40M
  - Construction Responsibility: APS

134) Baseline Upgrade b3740

- Overview of Reliability Problem
  - Criteria Violation: Glen Falls - Bridgeport
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Glen Falls - Bridgeport 138 kV Line: Replace Limiting Terminal Equipment
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.88M
  - Construction Responsibility: APS

135) Baseline Upgrade b3741

- Overview of Reliability Problem
  - Criteria Violation: Yukon - Charleroi 1
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Yukon - Charleroi No.1 138 kV Line: Replace Limiting Terminal Equipment
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.70M
  - Construction Responsibility: APS

136) Baseline Upgrade b3742

- Overview of Reliability Problem
  - Criteria Violation: Yukon - Charleroi 2
  - Criteria Test: Generation Deliverability

- Overview of Reliability Solution
  - Description of Upgrade: Yukon - Charleroi No.2 138 kV Line: Replace Limiting Terminal Equipment
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.45M
  - Construction Responsibility: APS

137) Baseline Upgrade b3743

- Overview of Reliability Problem
  - Criteria Violation: Cherry Run - Harmony Jct Tap
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: At Bedington Substation: Replace substation conductor, wavetrap, CT's and upgrade relaying
    At Cherry Run Substation: Replace substation conductor, wavetrap, CT's, disconnect switches, circuit breaker and upgrade relaying
    At Marlowe: Replace substation conductor, wavetrap, CT's and upgrade relaying.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $4.66M
  - Construction Responsibility: APS

138) Baseline Upgrade b3744

- Overview of Reliability Problem
  - Criteria Violation: Shanor - Krendale
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Replace one span of 1272 ACSR from Krendale substation to structure 35 (~630 ft)
    Replace one span of 1272 ACSR from Shanor Manor to structure 21 (~148 ft)
    Replace 1272 ACSR risers at Krendale & Shanor Manor Substations
    Replace 1272 ACSR Substation Conductor at Krendale Substation
    Replace relaying at Krendale Substation
    Revise Relay Settings at Butler & Shanor Manor Substations.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.75M
  - Construction Responsibility: APS

139) Baseline Upgrade b3745

- Overview of Reliability Problem
  - Criteria Violation: Carbon Center Substation
  - Criteria Test: Baseline
- Overview of Reliability Solution

- Description of Upgrade: Carbon Center Substation - Install Redundant Relaying
- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $0.57M
- Construction Responsibility: APS

140) Baseline Upgrade b3746

- Overview of Reliability Problem
    - Criteria Violation: Meadow Brook Substation
    - Criteria Test: Baseline
- Overview of Reliability Solution
    - Description of Upgrade: Meadow Brook Substation - Install Redundant Relaying
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.21M
    - Construction Responsibility: APS

141) Baseline Upgrade b3747

- Overview of Reliability Problem
    - Criteria Violation: Bedington Substation
    - Criteria Test: Baseline
- Overview of Reliability Solution
    - Description of Upgrade: Bedington Substation - Install Redundant Relaying
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.28M
    - Construction Responsibility: APS

142) Baseline Upgrade b3748

- Overview of Reliability Problem
    - Criteria Violation: The Jefferson – Clifty 345KV line is overload
    - Criteria Test: Summer Gen Deliv
- Overview of Reliability Solution
    - Description of Upgrade: Replace four Clifty Creek 345 kV 3000A switches with 5000 A 345 kV switches.
    - Upgrade In-Service Date: 6/1/2027
    - Estimated Upgrade Cost: $0.85M
    - Construction Responsibility: AEP

143) Baseline Upgrade b3749

- Overview of Reliability Problem
    - Criteria Violation: Overload on New Church – Piney 138 kV circuit
    - Criteria Test: Generation Deliverability

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild the New Church - Piney Grove 138 kV line
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $63.00M
  - Construction Responsibility: DPL

144) Baseline Upgrade b3750

- Overview of Reliability Problem
  - Criteria Violation: Overload on the Seward – Florence 115 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade Seward Terminal Equipment of the Seward-Blairsville 115 kV Line to increase the line rating such that the Transmission Line conductor is the limiting component.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.43M
  - Construction Responsibility: PENELEC

145) Baseline Upgrade b3751

- Overview of Reliability Problem
  - Criteria Violation: Overload on Roxbury to the AE1-071 115 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 6.4 miles of the Roxbury - Shade Gap 115 kV line from Roxbury to the AE1-071 115 kV ring bus with single circuit 115 kV construction
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $15.03M
  - Construction Responsibility: PENELEC

146) Baseline Upgrade b3752

- Overview of Reliability Problem
  - Criteria Violation: Overload on Shade Gap - AE1-071 115 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 7.2 miles of the Shade Gap - AE1-071 115 kV line section of the Roxbury - Shade Gap 115 kV line
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $17.43M
  - Construction Responsibility: PENELEC

147) Baseline Upgrade b3753

- Overview of Reliability Problem
  - Criteria Violation: Overload on the Tyrone North 115 /46 kV transformer #1
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Tyrone North 115 /46 kV transformer with a new standard 75 MVA top rated bank and upgrade the entire terminal to minimum 100 MVA capability for both SN and SE rating
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $2.82M
  - Construction Responsibility: PENELEC

148) Baseline Upgrade b3754

- Overview of Reliability Problem
  - Criteria Violation: Low voltage violation in the Belleville 46 kV vicinity
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: At Maclane tap: Construct a new three breaker ring bus to tie into the Warrior Ridge - Belleville 46 kV D line and the 1LK line
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $10.09M
  - Construction Responsibility: PENELEC

149) Baseline Upgrade b3755

- Overview of Reliability Problem
  - Criteria Violation: Low voltage and voltage drop violation at Locust 69 kV station
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Convert Locust Street 69kV from a Straight Bus to a Ring Bus.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $30.00M
  - Construction Responsibility: PSEG

150) Baseline Upgrade b3756

- Overview of Reliability Problem
  - Criteria Violation: Voltage drop violation at Maple Shade 69 kV
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Convert Maple Shade 69kV from a Straight Bus to a Ring Bus
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $33.90M

- Construction Responsibility: PSEG

151) Baseline Upgrade b3757

- Overview of Reliability Problem
  - Criteria Violation: Voltage drop violation at Medford and South Hampton 69 kV stations
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Convert existing Medford 69kV Straight bus to Seven breaker ring bus, construct a new 69kV line from Medford to the Mount Holly station, and install a capacitor bank at Medford
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $78.70M
  - Construction Responsibility: PSEG

152) Baseline Upgrade b3758

- Overview of Reliability Problem
  - Criteria Violation: Voltage drop violation at Harts Lane station
  - Criteria Test: FERC Form 715
- Overview of Reliability Solution
  - Description of Upgrade: Construct a new 69kV line from 14th Street to Harts Lane
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $34.40M
  - Construction Responsibility: PSEG

153) Baseline Upgrade b3759

- Overview of Reliability Problem
  - Criteria Violation: Overload of 115kV Line #23 from Oak Ridge - AC2-079
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor approximately 10.5 miles of 115kV Line #23 segment from Oak Ridge to AC2-079 Tap to minimum emergency ratings of 393 MVA Summer / 412 MVA Winter
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $23.50M
  - Construction Responsibility: Dominion

154) Baseline Upgrade b3760

- Overview of Reliability Problem
  - Criteria Violation: Interregional TMEP Analysis
  - Criteria Test: 2022 CSP Study
- Overview of Reliability Solution

- Description of Upgrade: At Powerton Sub, replace most limiting facility 800A wave trap with 2000A wave trap on the Powerton-Towerline 138kV line terminal
- Upgrade In-Service Date: 6/1/2025
- Estimated Upgrade Cost: $0.20M
- Construction Responsibility: ComEd

155) Baseline Upgrade b3761

- Overview of Reliability Problem
  - Criteria Violation: Carbon Center to Elko
  - Criteria Test: Baseline
- Overview of Reliability Solution
  - Description of Upgrade: Install 138 kV Breaker on the Ridgway 138/46 kV #2 Transformer
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $1.10M
  - Construction Responsibility: APS

156) Baseline Upgrade b3762

- Overview of Reliability Problem
  - Criteria Violation: The Fawkes-Duncannon Lane Tap 69 kV line (LGEE-EKPC tie line) is overloaded
  - Criteria Test: EKPC 715 Criteria, N-1
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild EKPC's Fawkes-Duncannon Lane Tap 556.5 ACSR 69 kV line section (7.2 miles) using 795 ACSR.
  - Upgrade In-Service Date: 12/1/2026
  - Estimated Upgrade Cost: $8.50M
  - Construction Responsibility: EKPC

157) Baseline Upgrade b3763

- Overview of Reliability Problem
  - Criteria Violation: Jug Street 138kV breakers M, N,BC,BF, BD, BE,D, H, J, L, BG, BH, BJ, BK are overdutied.
  - Criteria Test: short circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Jug Street 138kV breakers M, N, BC, BF, BD, BE, D, H, J, L, BG, BH, BJ, BK with 80KA breakers
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $14.00M
  - Construction Responsibility: AEP

158) Baseline Upgrade b3764

- Overview of Reliability Problem
  - Criteria Violation: Hyatt 138kV breakers AB1 and AD1 are overdutied.
  - Criteria Test: short circuit
- Overview of Reliability Solution
  - Description of Upgrade: Replace the Hyatt 138kV breakers AB1 and AD1 with 63kA breakers
  - Upgrade In-Service Date: 6/1/2024
  - Estimated Upgrade Cost: $2.00M
  - Construction Responsibility: AEP

159) Baseline Upgrade b3765

- Overview of Reliability Problem
  - Criteria Violation: High voltage at Mainesburg
  - Criteria Test: Spare Equipment
- Overview of Reliability Solution
  - Description of Upgrade: Purchase one 80 MVAR 345 kV spare reactor, to be located at the Mainesburg station.
  - Upgrade In-Service Date: 12/1/2022
  - Estimated Upgrade Cost: $6.44M
  - Construction Responsibility: PENELEC

160) Baseline Upgrade b3766.1

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: Hayes – New Westville 138 kV line: Build ~0.19 miles of 138 kV line to the Indiana/ Ohio State line to connect to AES's line portion of the Hayes – New Westville 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction and ROW.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $0.38M
  - Construction Responsibility: AEP

161) Baseline Upgrade b3766.2

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: Hayes – Hodgin 138 kV line: Build ~0.05 miles of 138 kV line with the conductor size 795 ACSR26/7 Drake. The following cost includes the line construction, ROW, and fiber.

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $1.22M
- Construction Responsibility: AEP

162) Baseline Upgrade b3766.3

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: Hayes 138 kV: Build a new 4-138 kV circuit breaker ring bus. The following cost includes the new station construction, property purchase, metering, station fiber and the College Corner –Randolph 138 kV line connection.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $7.44M
  - Construction Responsibility: AEP

163) Baseline Upgrade b3766.4

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: New Westville – AEP Hodgin 138kV Line: Construct a 138kV 1.86-mile single circuit transmission line. This transmission line will help loop the radial load served at New Westville as part of the overall effort to improve reliability in this area. Also, it provides a source to feed New Westville load while the 138kV tie built back into the AES Ohio system
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $3.70M
  - Construction Responsibility: Dayton

164) Baseline Upgrade b3766.5

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: New Westville – West Manchester 138kV Line: Construct a new approximate 11-mile single circuit 138kV line from New Westville to the Lewisburg tap off 6656. Convert a portion of 6656 West Manchester – Garage Rd 69kV line between West Manchester - Lewisburg to 138kV operation (circuit is built to 138kV). This will utilize part of the line already built to 138kV and will take place of the 3302 that currently feeds New Westville. The 3302 line will be retired as part of this project.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $16.00M

- Construction Responsibility: Dayton

165) Baseline Upgrade b3766.6

- Overview of Reliability Problem
  - Criteria Violation: the College Corner – Collinsville 138KV line is overload
  - Criteria Test: Summer/Winter Gen deliv
- Overview of Reliability Solution
  - Description of Upgrade: West Manchester Substation: The West Manchester Substation will be expanded to a double bus double breaker design where AES Ohio will install one 138kV circuit breaker, a 138/69kV transformer, and eight new 69kV circuit breakers. These improvements will improve help improve a non-standard bus arrangement where there is only one bus tie today and will improve the switching arrangement for the West Sonora Delivery Point.
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $9.90M
  - Construction Responsibility: Dayton

166) Baseline Upgrade b3768

- Overview of Reliability Problem
  - Criteria Violation: Overload on Germantown - Straban - Lincoln 115 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Rebuild/Reconductor the Germantown - Lincoln 115 kV Line. Approximately 7.6 miles. Upgrade limiting terminal equipment at Lincoln, Germantown and Straban
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $17.36M
  - Construction Responsibility: ME

167) Baseline Upgrade b3769

- Overview of Reliability Problem
  - Criteria Violation: Overload on TMI 500/230 kV transformer
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Install second TMI 500/230kV Transformer with additional 500 and 230 bus expansions
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $30.19M
  - Construction Responsibility: ME

168) Baseline Upgrade b3770

- Overview of Reliability Problem
  - Criteria Violation: Overload on Graceton - Brunner Island 230 kV

- Criteria Test: Generation Deliverability

- Overview of Reliability Solution
  - Description of Upgrade: Rebuild 1.4 miles of existing single circuit 230 kV tower line between BGE's Graceton substation to the Brunner Island PPL tie-line at the MD/PA state line to double circuit steel pole line with one (1) circuit installed to uprate 2303 circuit
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $8.40M
  - Construction Responsibility: BGE

169) Baseline Upgrade b3771

- Overview of Reliability Problem
  - Criteria Violation: Overload on Conastone - North West 230 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor two (2) 230 kV circuits from Conastone to Northwest #2
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $37.76M
  - Construction Responsibility: BGE

170) Baseline Upgrade b3772

- Overview of Reliability Problem
  - Criteria Violation: Overload on Messick Rd - Morgan 238 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Reconductor 27.3 miles of the Messick Road - Morgan 138 kV Line from 556 ACSR to 954 ACSR. At Messick Road Substation: Replace 138 kV wave trap, circuit breaker, CT's, disconnect switch, and substation conductor and upgrade relaying. At Morgan Substation: Upgrade Relaying
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $49.23M
  - Construction Responsibility: APS

171) Baseline Upgrade b3773

- Overview of Reliability Problem
  - Criteria Violation: Low voltage in the McConnellsburg 138kV vicinity
  - Criteria Test: N-1-1
- Overview of Reliability Solution
  - Description of Upgrade: McConnellsburg 138 kV Susbtation: Install 33 MVAR switched capacitor, 138 kV Breaker, and associated relaying

- Upgrade In-Service Date: 6/1/2027
- Estimated Upgrade Cost: $3.05M
- Construction Responsibility: APS

172) Baseline Upgrade b3774

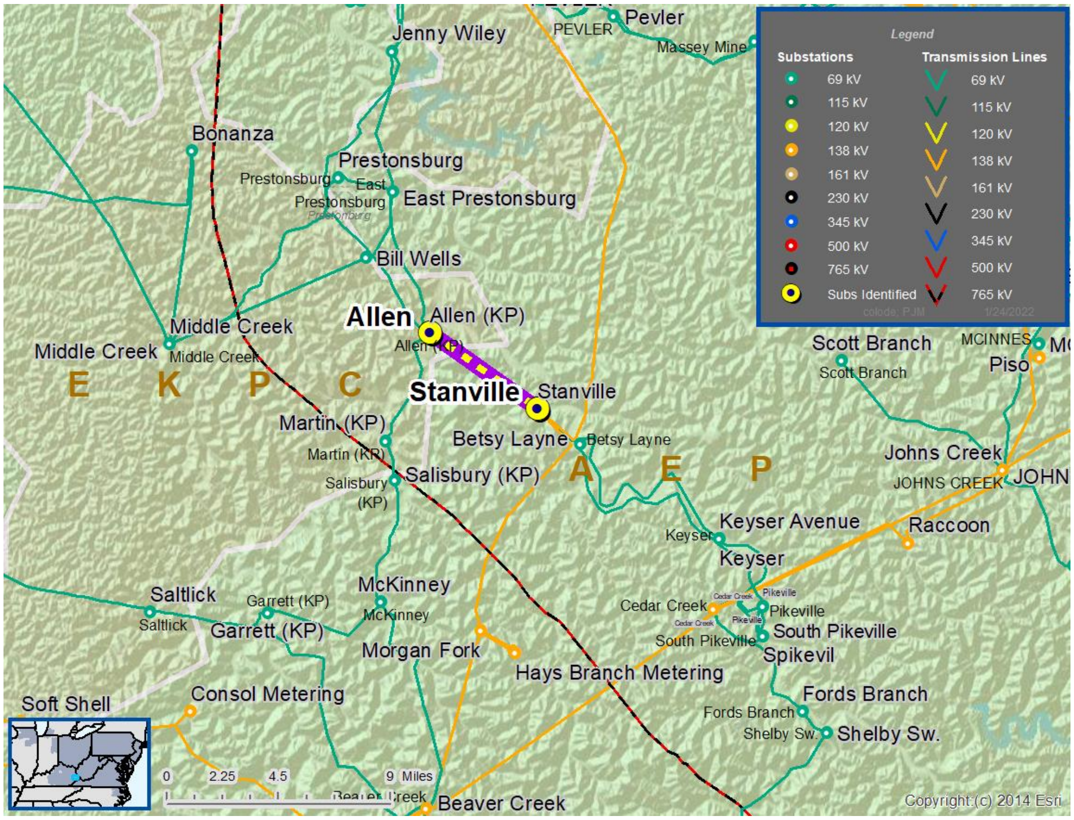
- Overview of Reliability Problem
  - Criteria Violation: Overload on Brunner Island - Yorkanna 230 kV
  - Criteria Test: Generation Deliverability
- Overview of Reliability Solution
  - Description of Upgrade: Upgrade terminal equipment at Brunner Island (on the Brunner Island - Yorkana 230 kV circuit)
  - Upgrade In-Service Date: 6/1/2027
  - Estimated Upgrade Cost: $2.50M
  - Construction Responsibility: PPL

Baseline Project b3353: Allen 46 kV Station Rebuild Baseline Conversion

AEP Transmission Zone

In the 2026 RTEP winter case, the Stanville-Allen 46 kV line section is overloaded for multiple N-1 outage combination.

Map 1. **b3353: Allen 46 kV Area**



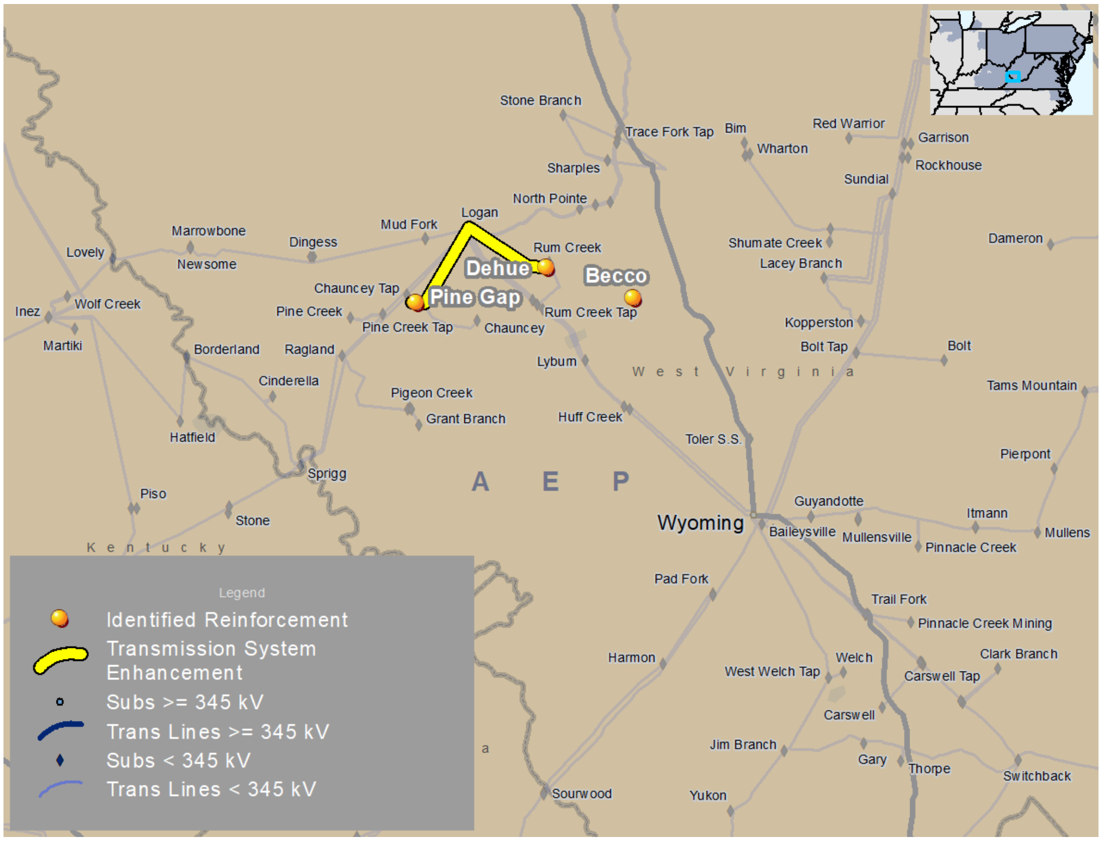
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is an existing supplemental project that has been converted to a baseline. The supplemental project scope, slated to be in service by the end of 2023, addresses the severe flooding issue and obsolete equipment at the existing Allen station. The supplemental project was converted to a baseline as it addresses both the supplemental needs identified through the M-3 process and the identified reliability needs in the 2026 RTEP winter case. The proposed conversion of the supplemental project to a baseline does not add any cost to the RTEP. The solution is to rebuild the Allen 46 kV station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7-foot concrete platforms and a control house raised by a 10-foot platform to mitigate flooding concerns. Five 69 kV 3000 A 40 kA circuit breakers in a ring bus (operated at 46 kV) configuration will be installed with a 13.2 MVAR capacitor bank. The existing Allen station will be retired. A 0.20 mile segment of the Allen-East Prestonsburg 46 kV line will be relocated to the new station. The new McKinney-Allen line extension will extend around the south and east sides of the existing Allen station to the new Allen station being built in the clear. A short segment of new single circuit 69 kV line and a short segment of new double circuit 69 kV line (both operated at 46 kV) will be added to the line to tie into the new Allen station bays. A segment of the Stanville-Allen line will also have to be relocated to the new station. A 0.25 mile segment of the existing Allen-Prestonsburg single circuit will be relocated, and the relocated line segment will require construction of one custom self-supporting double circuit dead-end structure and single circuit suspension structure. A short segment of new double circuit 69 kV line (energized at 46 kV) will be added to tie into the new Allen station bays, which will carry Allen-Prestonsburg and Allen-East Prestonsburg 46 kV lines. A temporary 0.15 mile section double circuit line will be constructed to keep both lines energized during construction. Remote end work will also be required at Prestonsburg, Stanville and McKinney 46 kV stations. The estimated cost for this project is $16 million, with a required in-service date of December 2026. The projected in-service date is December 2023, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3348: Dehue Area Improvements

AEP Transmission Zone

In the 2026 RTEP light load case, the Becco-Slagle, Dehue-Pine Gap and Dehue-Slagle 46 kV lines are overloaded for an N-1 outage combination. There are also low voltage and voltage drop violations at Three Fork, Toney Fork, Cyclone, Pardee, Crane, Latrobe, Becco, Slagle and Dehue 46 kV buses for an N-1 outage combination.

Map 2. **b3348: Dehue Area**



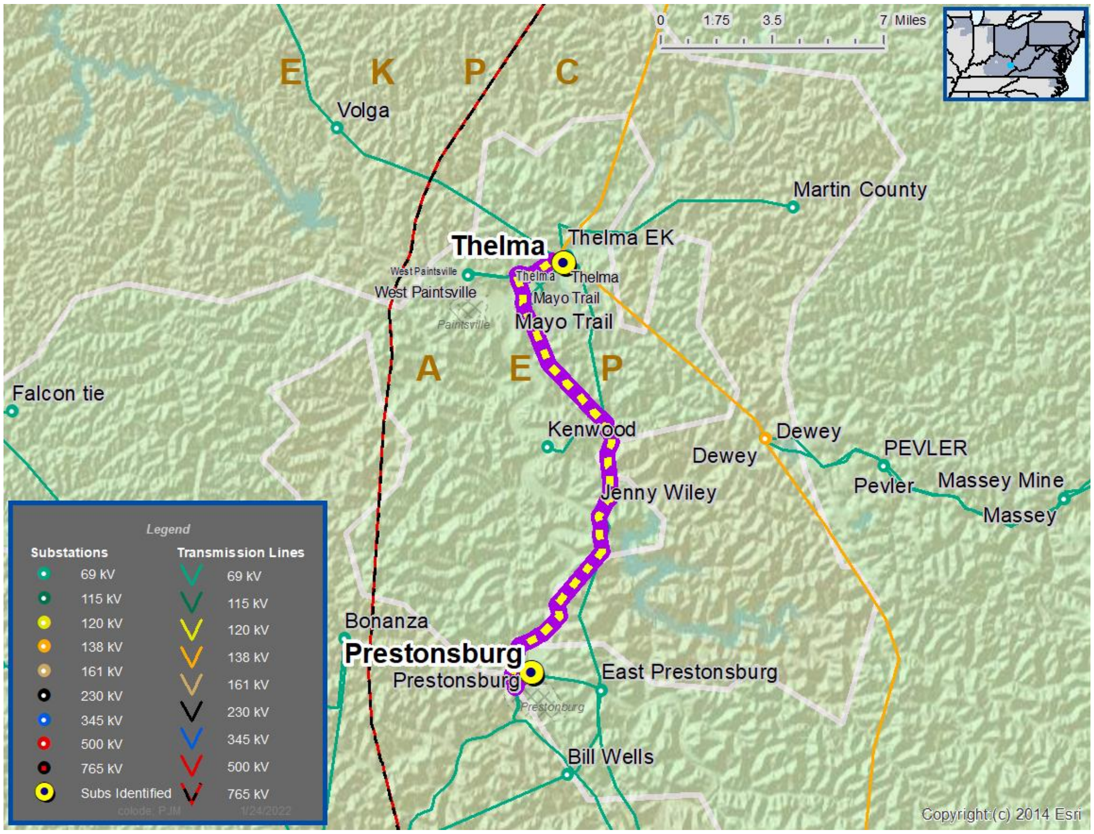
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to construct a new 138 kV Tin Branch single bus station to replace Pine Gap station, consisting of a 138 kV box bay with a distribution transformer and 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Sprigg stations), and distribution will have one 12 kV feed. The project installs two 138 kV circuit breakers on the line exits and a 138 kV circuit switcher for the new transformer. A new 138/46/12 kV Argyle station will be constructed to replace the Dehue station, with a 138 kV ring bus using a breaker-and-a-half configuration, an autotransformer (46 kV feed) and a distribution transformer (12 kV distribution bay). Two 138 kV lines will feed the Argyle station (from Logan and Wyoming stations), and there will also be a 46 kV feed from this station to Becco station (distribution will have two 12 kV feeds). The project retires the Dehue station in its entirety, and brings the Logan-Sprigg No. 2 138 kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138 kV line. The Logan-Wyoming No. 1 138 kV circuit will be brought in and out of the new Argyle substation. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 No. 8 ALUMOWELD, and one shield wire will be optical ground wire (OPGW). Approximately 10 miles of the 46 kV line between Becco and the new Argyle substation will be rebuilt, and approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey substation will be retired. Relay settings need to be adjusted due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco and Chauncey substations. The estimated cost for this project is $65.8 million, with a required in-service of November 2026. The projected in-service date is June 2026, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3361: Prestonsburg-Thelma 46 kV Rebuild

AEP Transmission Zone

In the 2026 RTEP winter case, there are voltage magnitude and voltage drop violations at Mckinney, Salsbury, Allen, East Prestonsburg, Prestonsburg, Middle Creek and Kenwood 46 kV buses for multiple N-1 outage combinations.

Map 3. **b3361: Prestonsburg-Thelma 46 kV**



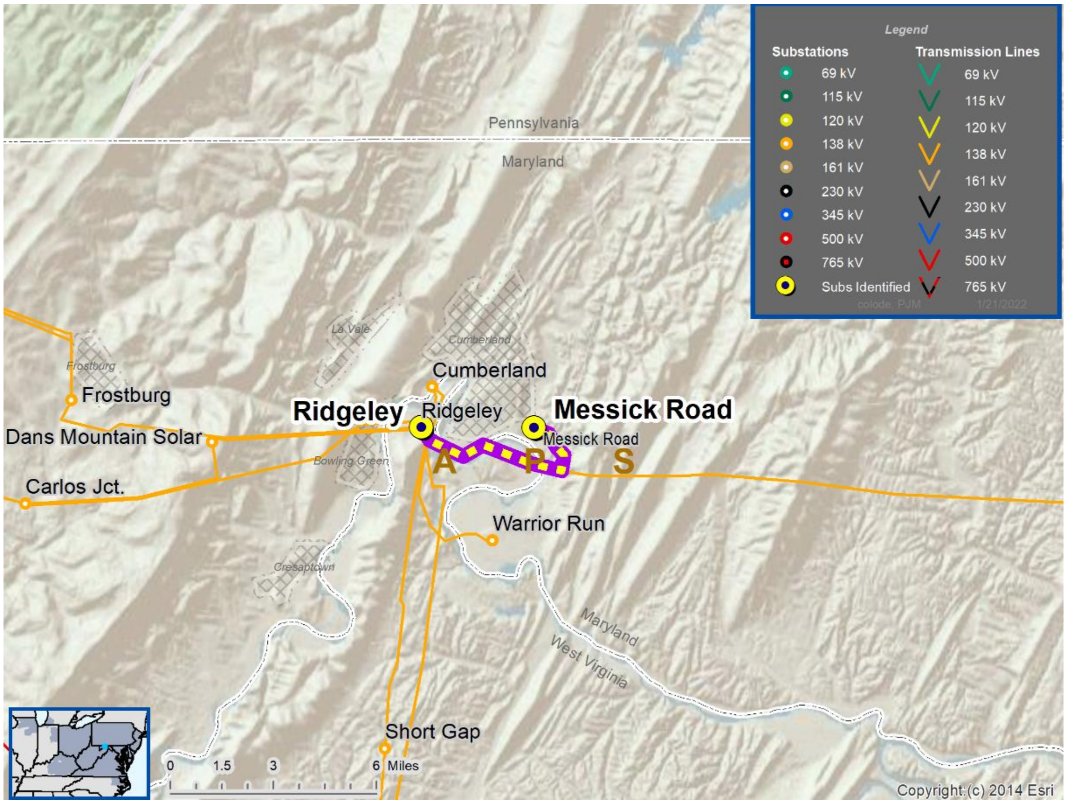
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, addresses both the identified reliability needs and a supplemental need identified through the M-3 process. There are equipment condition issues with structures that make up the Prestonsburg-Thelma 46 kV line. These conditions include damaged/rotted poles, guy wires and cross arms. The majority of this line utilizes 1960s wood structures and 336.4 ACSR conductor. The solution is to rebuild the Prestonsburg-Thelma 46 kV line (approximately 14 miles) and retire Jenny Wiley 46 kV switching station. The estimated cost for this project is $33.01 million, with a required in-service date of December 2026. The projected in-service date is October 2025, and the local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3683: Messick Road-Ridgeley 138 kV Upgrades

APS Transmission Zone

In the 2026 RTEP summer case, the Messick Road-Ridgeley 138 kV line is overloaded for multiple N-2 outage combinations.

Map 4. **b3683: Messick Road-Ridgeley 138 kV**



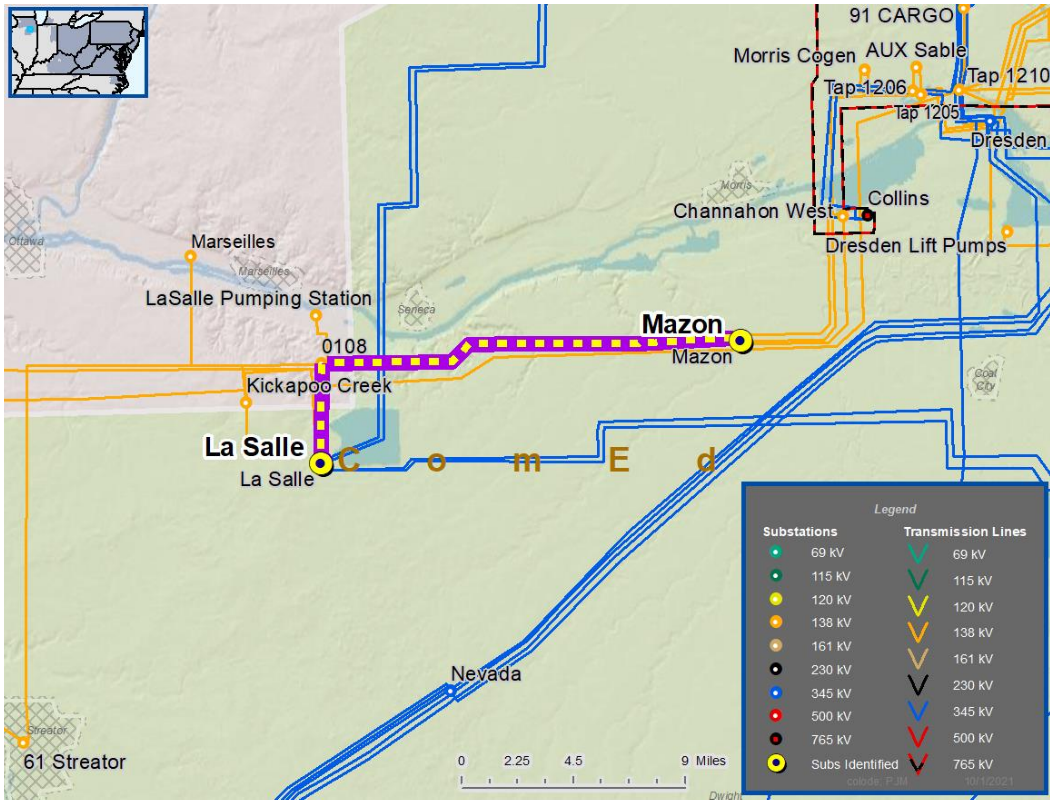
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to reconductor the existing 556.5 ACSR line segments on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR. The remote end equipment for the Messick Road-Ridgeley WC4 138 kV line will also be replaced. The estimated cost for this project is $11.2 million, with a required and projected in-service date of June 2026. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3677: LaSalle-Mazon 138 kV Rebuild

ComEd Transmission Zone

In the 2026 RTEP light load case, the LaSalle-Mazon 138 kV line is overloaded for an N-2 outage.

Map 5. **b3677: LaSalle-Mazon 138 kV**



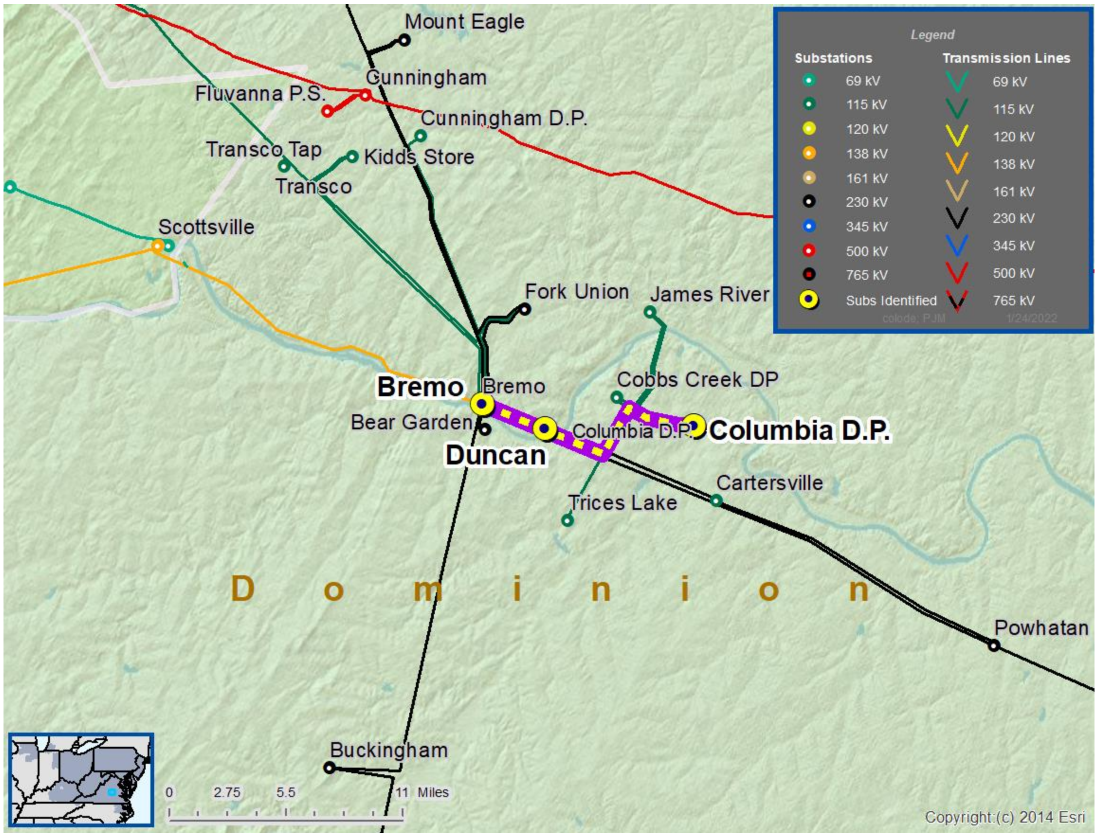
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild a 13 mile section of 138 kV line 0108 between LaSalle and Mazon with 1113 ACSR or higher rated conductor. The estimated cost for this project is $42.06 million, with a required in-service date of November 2026. The projected in-service date is December 2024, and the local transmission owner, ComEd, will be designated to complete this work.

Baseline Project b3686: Bremo-Columbia D.P. 115 kV Switching Station

Dominion Transmission Zone

In the 2026 RTEP winter case, the Bremo-Columbia D.P. 115 kV line (No. 4) is a radial transmission line and exceeds the 700 MW-Mile threshold under Dominion's FERC 715 Planning Criteria.

Map 6. **b3686: Bremo-Columbia D.P. 115 kV**



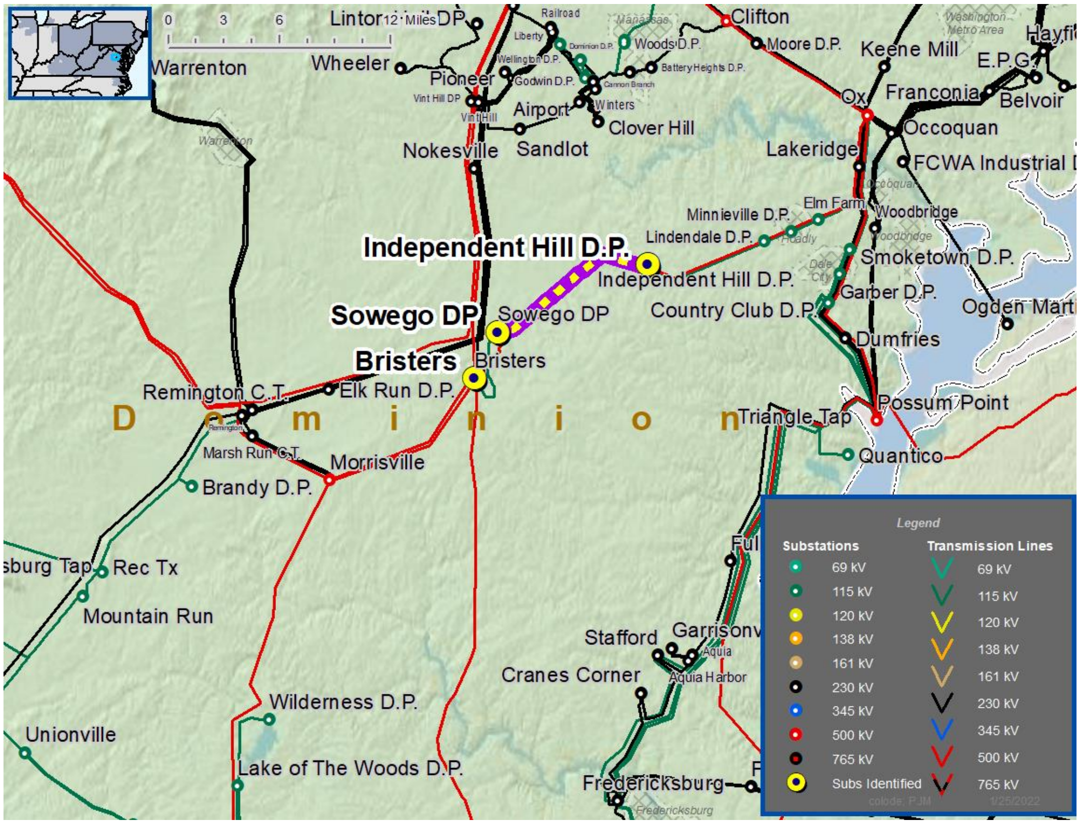
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to purchase land close to the bifurcation point of line No. 4 (where the line is split into two sections) and build a new 115 kV switching station called Duncan Store 115 kV. The new switching station will require space for an ultimate transmission interconnection consisting of a 115 kV six-breaker ring bus (with three breakers installed initially). The estimated cost for this project is $16 million, with a required and projected in-service date of December 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3687: Bristers-Minnieville D.P. 115 kV Rebuild

Dominion Transmission Zone

In the 2026 RTEP summer case, the Bristers 230/115 kV transformer is overloaded for an N-1 outage under the generator deliverability study and for Dominion's Stress Case (FERC 715 Planning Criteria). The 115 kV line No. 183 (Sowego-Independent Hill segment) is overloaded for N-1 and N-2 outages, along with multiple N-1 outage combinations under PJM reliability studies and Dominion's Stress Case.

Map 7. **b3687: Bristers-Minnieville D.P. 115 kV Area**



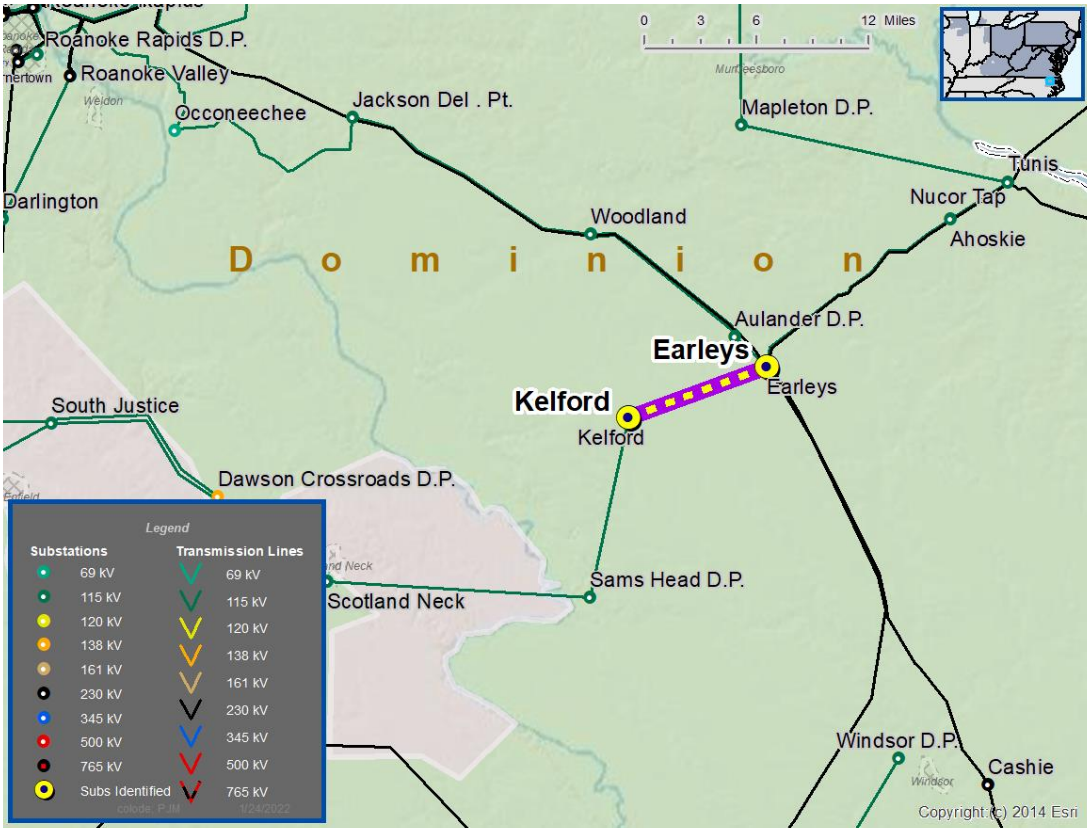
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild of the approximately 15.1-mile-long line segment between Bristers and Minnieville D.P. with 2-768 ACSS and 4000 A supporting equipment from Bristers to Ox to allow for future 230 kV capability of 115 kV line No. 183 (Sowego-Independent Hill segment). The estimated cost for this project is $30 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3684: Earleys-Kelford 115 kV Rebuild

Dominion Transmission Zone

In the 2026 RTEP summer case, the 115 kV line No. 126 segment from Earleys to Kelford is overloaded for an N-2 outage.

Map 8. **b3684: Earleys-Kelford 115 kV**



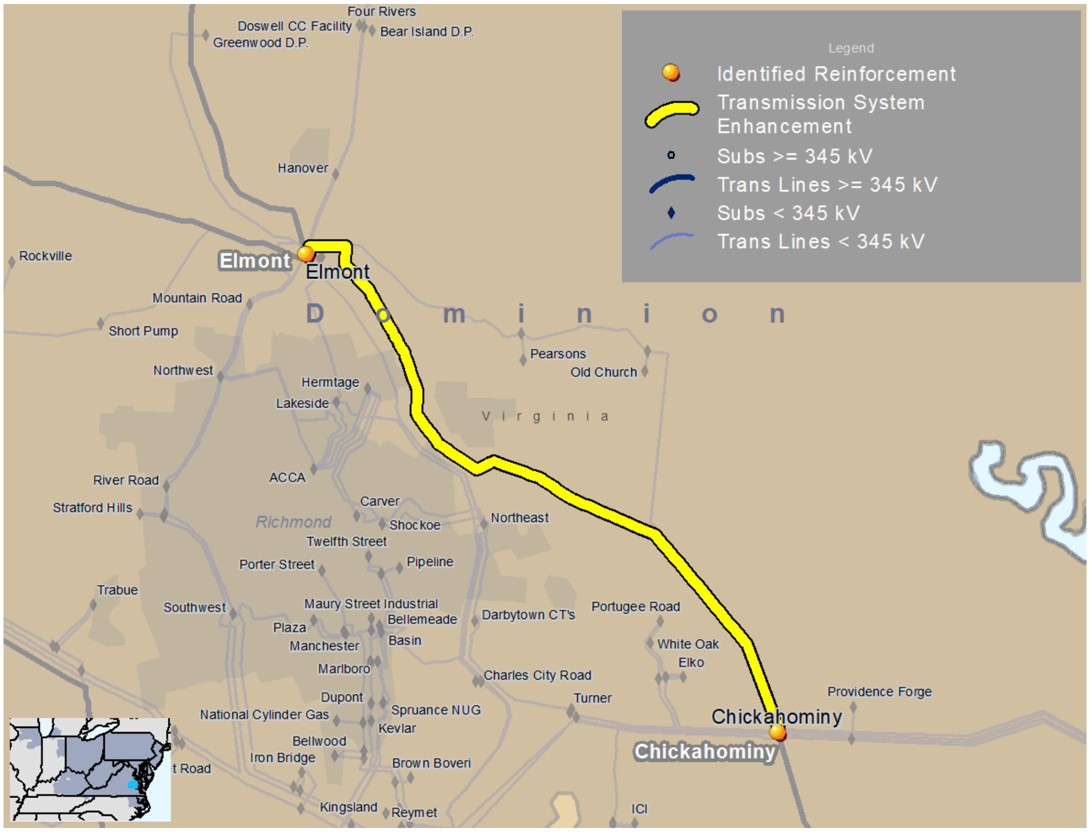
The recommended solution, which was excluded from the competitive proposal process for the below 200 kV exclusion, is to rebuild 12.4 miles of 115 kV line No. 126 segment from Earleys to Kelford line with a summer emergency rating of 262 MVA and replace structures as needed to support the new conductor. The breaker switch 13668 at Earleys will also be upgraded from 1200 A to 2000 A. The estimated cost for this project is $18.75 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3692: Elmont-Chickahominy 500 kV Rebuild

Dominion Transmission Zone

The Elmont-Chickahominy 500 kV line (No. 557) was constructed in 1971 with 2500 ACAR conductor and 5-series Corten towers that need to be rebuilt to current standards based on Dominion’s End-of-Life Criteria.

Map 9. **b3692: Elmont-Chickahominy 500 kV**



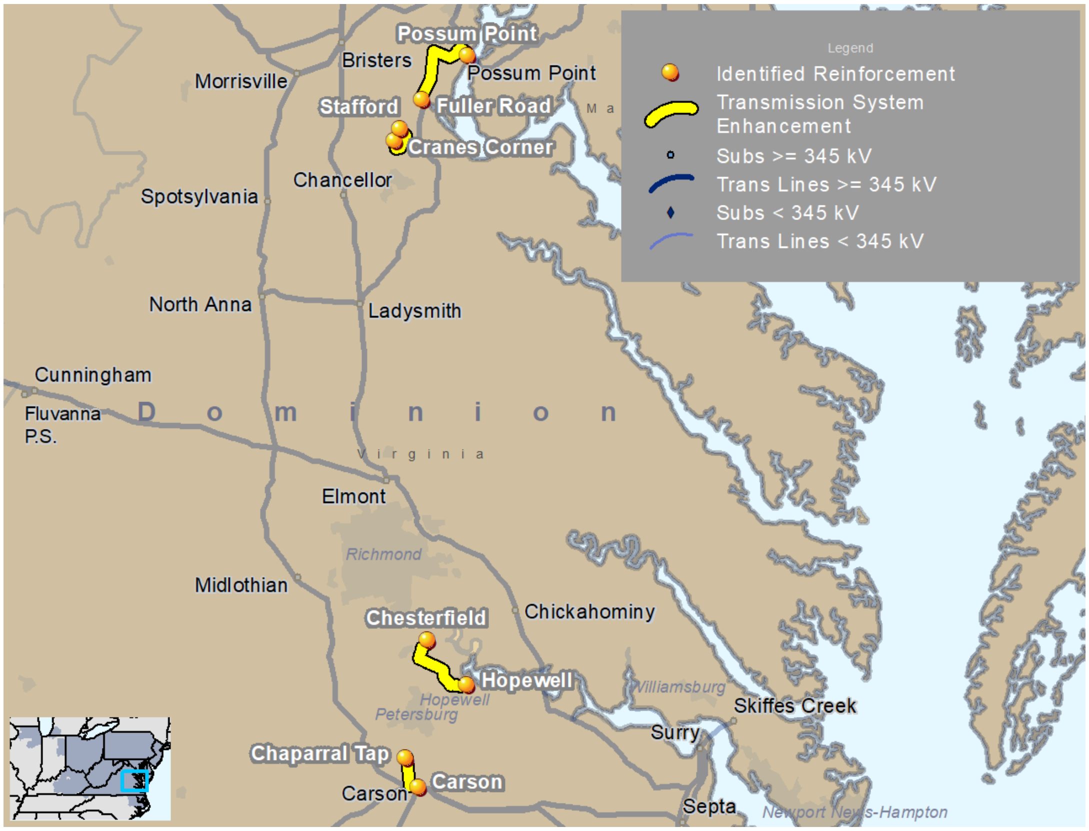
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to rebuild approximately 27.7 miles of 500 kV transmission line from Elmont to Chickahominy with current 500 kV standards construction practices to achieve a summer rating of 4330 MVA. The estimated cost for this project is $58.16 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3694: Fredericksburg/Carson/Hopewell Area Improvements

Dominion Transmission Zone

In the 2026 RTEP summer case, in the Fredericksburg area, the Cranes Corner-Stafford 230 kV line (No. 2104) is overloaded for an N-1 and N-2 outage as well as under Dominion stress case criteria, and there is load loss of 307 MW for N-1 outage combinations. In the Carson area, the Carson 500/230 kV transformer No. 2 is overloaded for an N-2 outage, and the Carson-Chaparral 230 kV line (No. 249) is overloaded for an N-1 outage. In the Hopewell area, the Chesterfield-Hopewell 230 kV line (No. 211) is overloaded for an N-1 outage, and the Chesterfield-Hopewell 230 kV line (No. 228) is overloaded for an N-1 and N-2 outage.

Map 10. **b3694: Fredericksburg/Carson/Hopewell Area Improvements**



The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is a comprehensive project that addresses all three areas.

In the Fredericksburg area, the project will convert 115 kV line No. 29 (Aquia Harbor-Possum Point) to 230 kV (extended line No. 2104) and swap line No. 2104 (Cranes Corner-Stafford 230 kV) and converted line No. 29 at Aquia Harbor backbone termination. The project will also upgrade terminal equipment at Possum Point, Aquia Harbor and Fredericksburg 230 kV. The project will add a new breaker at the Fredericksburg 230 kV bay and reconfigure 230 kV line terminations. Approximately 7.6 miles of 230 kV line No. 2104 (Cranes Corner-Stafford) and approximately 0.34 miles of 230 kV line No. 2104 (Stafford-Aquia Harbor) will be reconductored/rebuilt to achieve a summer rating of 1047 MVA (terminal equipment at Cranes Corner will be upgraded to not limit the new conductor rating). The project will upgrade the wave trap and line leads at 230 kV line No. 2090 Ladysmith CT terminal to achieve 4000 A rating. The Fuller Road substation will be upgraded to feed the Quantico substation via a 115 kV radial line, and a four-breaker ring will be installed to break 230 kV line No. 252 into two new lines: 1) No. 252 between Aquia Harbor to Fuller Road, and 2) No. 9282 between Fuller Road and Possum Point. A 230/115 kV transformer will also be installed, which will serve Quantico substation.

In the Carson area, the project will energize the in-service spare 500/230 kV Carson No. 1 transformer, and partially wreck and rebuild 10.34 miles of 230 kV line No. 249 (Carson-Locks) to achieve a minimum summer emergency rating of 1047 MVA (terminal equipment at Carson and Locks will be upgraded to not limit the new conductor rating). The project includes the wreck and rebuild of 5.4 miles of 115 kV line No. 100 (Locks-Harrowgate) to achieve a minimum summer emergency rating of 393 MVA (terminal equipment at Locks and Harrowgate will be upgraded to not limit the new conductor rating), and will perform line No. 100 Chesterfield terminal relay work.

In the Hopewell area, the project will reconductor approximately 2.9 miles each of 230 kV lines No. 211 (Chesterfield-Hopewell) and No. 228 (Chesterfield-Hopewell) to achieve a minimum summer emergency rating of 1046 MVA (equipment at Chesterfield and Hopewell substations will be upgraded to not limit ratings on lines No. 211 and No. 228).

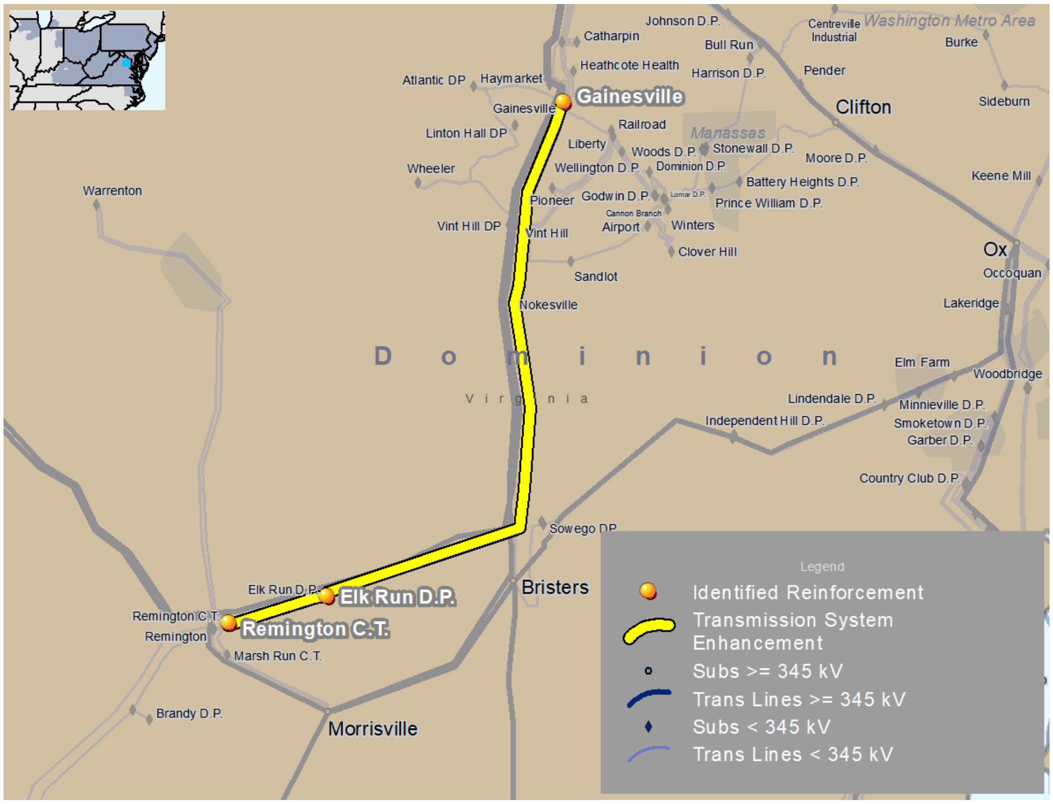
The total estimated cost for this project is $93.41 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3689: Remington CT-Gainesville 230 kV Reconductor

Dominion Transmission Zone

In the 2026 RTEP summer case, the Remington CT-Gainesville 230 kV line (No. 2114) is overloaded for multiple N-1 and N-2 outages.

Map 11. **b3689: Remington CT-Gainesville 230 kV**



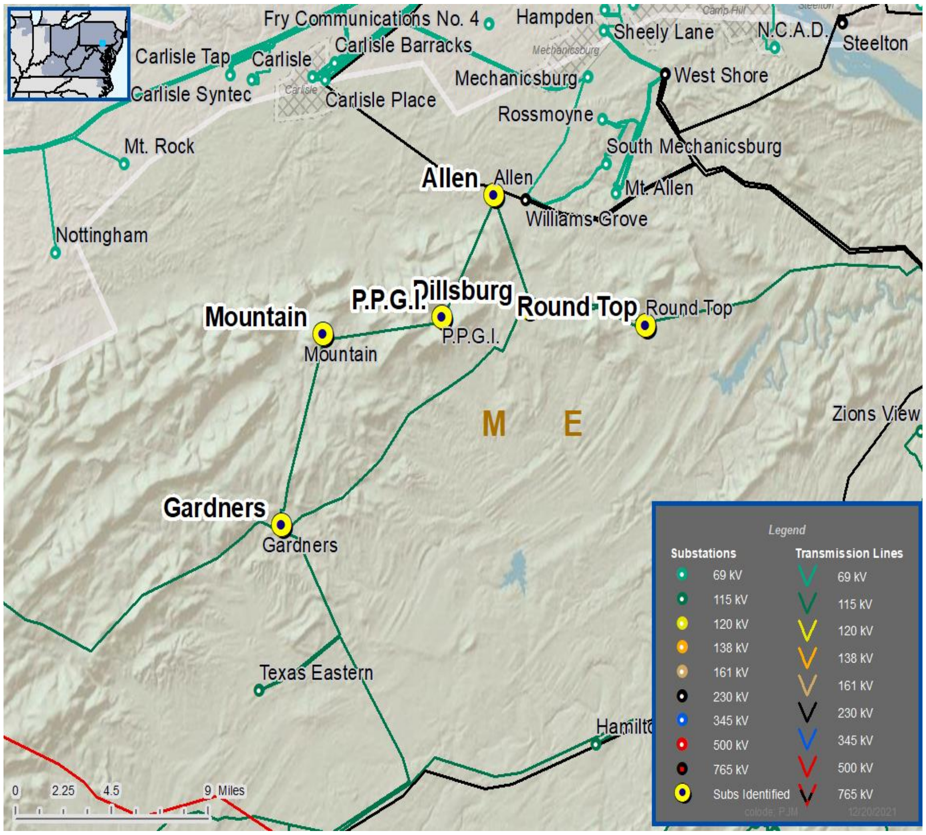
The recommended solution, solicited through the 2021 Window 1 competitive proposal process, is to reconductor approximately 24.42 miles of Remington CT-Elk Run-Gainesville 230 kV line (No. 2114) to achieve a summer rating of 1574 MVA (by fully reconductoring the line and upgrading the wave trap and substation conductor at Remington CT and Gainesville 230 kV). The project will replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 4000 A 80 kA breakers and associated equipment, including breaker leads as necessary, to address breaker duty issues identified in short circuit analysis. The estimated cost for this project is $30.68 million, with a required and projected in-service date of June 2026. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3715: Allen 115 kV Area Improvements

ME Transmission Zone

In the 2026 RTEP summer case, there are voltage magnitude and voltage drop violations at several 115 kV stations in the Allen vicinity for multiple N-1 outage combinations.

Map 12. **b3715: Allen 115 kV Area**



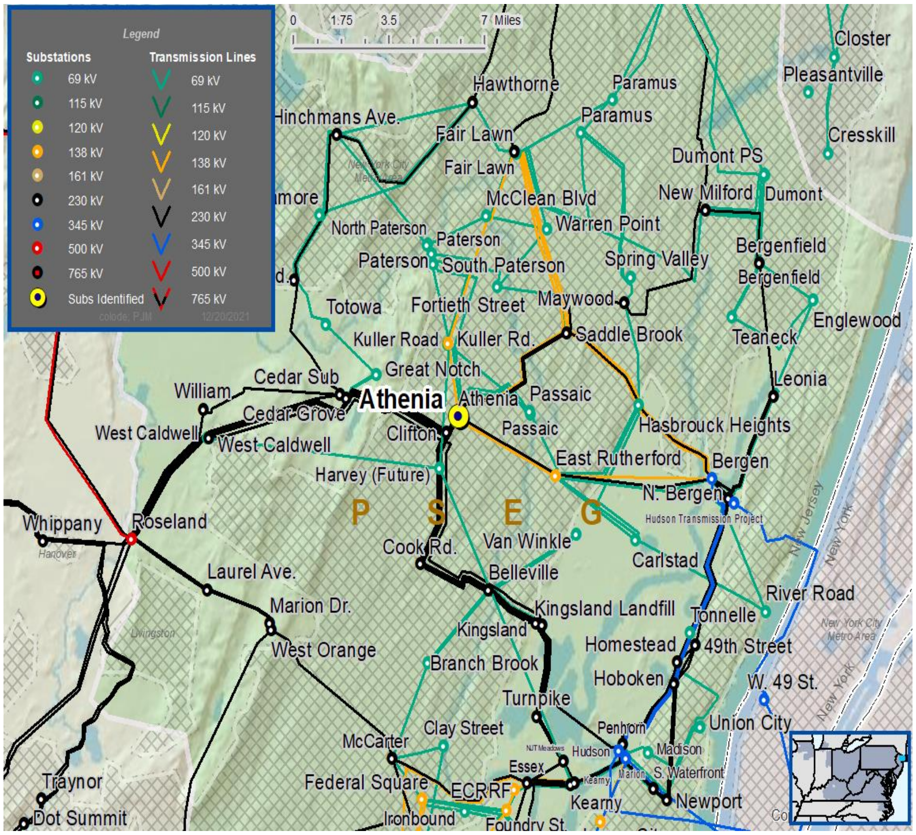
The recommended solution, which was solicited through the 2021 Window 1, is to install a new 300 MVA 230/115 kV transformer at the existing PPL Williams Grove substation and construct a new 3.4 mile 115 kV single-circuit transmission line from Williams Grove to Allen substation. A new four breaker ring bus switchyard will be installed at Allen, near the existing ME Allen substation on adjacent property presently owned by FirstEnergy. The Round Top-Allen and Allen-PPGI (P.P.G. Industries) 115 kV lines will terminate into the new switchyard. The estimated cost for this project is $17.82 million, with a required and projected in-service date of June 2026. The local transmission owners, ME and PPL, will be designated to complete this work.

Baseline Project b3705: Athenia 230/138 kV Transformer Replacement

PSEG Transmission Zone

Per PSEG's FERC 715 planning criteria evaluation, the Athenia 230/138 kV transformer No. 220-1 was identified for replacement based on equipment performance, condition assessment and system needs. The No. 220-1 transformer at Athenia has been heavily gassing for many years and has been de-gassed multiple times due to high levels of combustible gas in the main tank.

Map 13. **b3705: Athenia 230/138 kV**



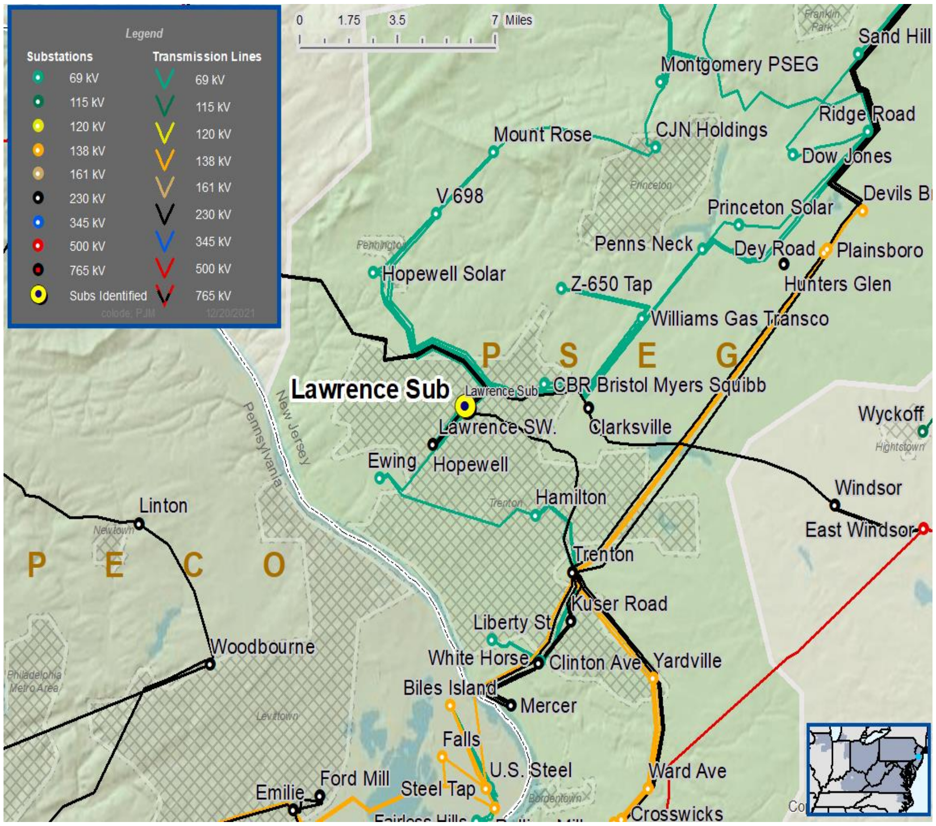
The recommended solution, which was solicited through the 2021 Window 3, is to replace the existing Athenia 230/138 kV transformer No. 220-1. The estimated cost for this project is $13.04 million, with a required and projected in-service date of June 2026. The local transmission owner, PSEG, will be designated to complete this work.

Baseline Project b3704: Lawrence 230/69 kV Transformer Replacement

PSEG Transmission Zone

Per PSEG's FERC 715 planning criteria evaluation, the Lawrence 230/69 kV transformer No. 220-4 was identified for replacement based on equipment performance, condition assessment and system needs.

Map 14. **b3704: Lawrence 230/69 kV**



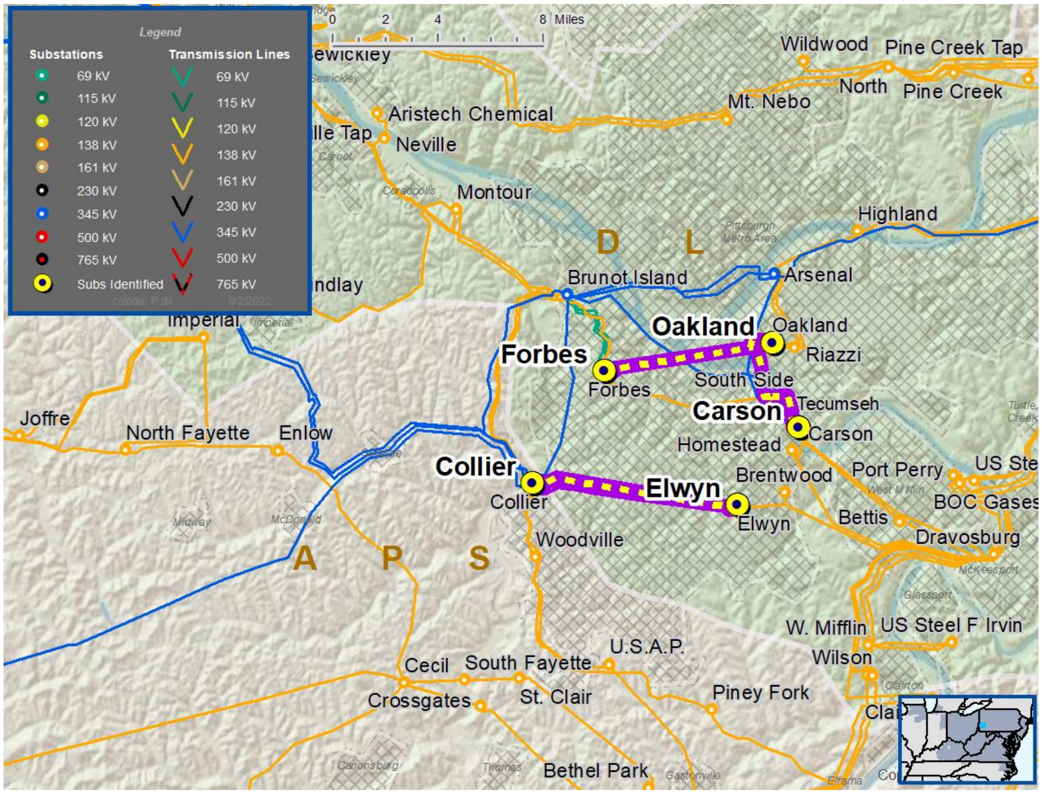
The recommended solution, which was solicited through the 2021 Window 3, is to replace the Lawrence switching station 230/69 kV transformer No. 220-4 and its associated circuit switchers with a new larger-capacity transformer with Load Tap Changer (LTC) and new dead tank circuit breaker. A new 230 kV gas insulated breaker, associated disconnects, overhead bus and other necessary equipment will be installed to complete the bay within the Lawrence 230 kV switchyard. The estimated cost for this project is $13.36 million, with a required and projected in-service date of June 2026. The local transmission owner, PSEG, will be designated to complete this work.

Baseline Project b3717: Cheswick 1 Deactivation Reinforcements

DL Transmission Zone

Cheswick 1 deactivated in March 2022; however, additional overloads were identified in the 2023 RTEP summer case. The Collier-Elwyn No. 1 and No. 2, Forbes-Oakland, and Carson-Oakland 138 kV transmission lines are overloaded for multiple N-1 outage combinations.

Map 15. **b3717: Cheswick 1 Deactivation**



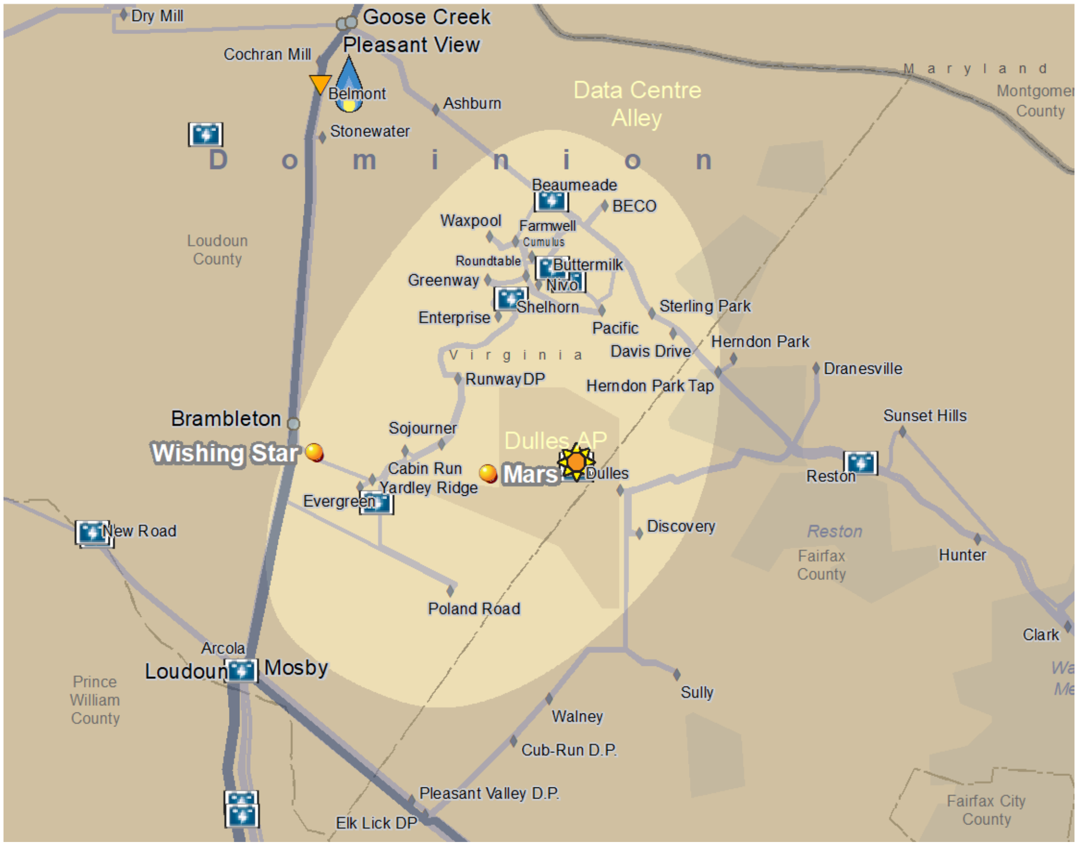
The recommended solution is to install a series reactor on Cheswick-Springdale 138 kV line, replace four structures and reconductor Duquesne Light Company's portion of Plum-Springdale 138 kV line. Associated communication and relay setting changes are also needed at Plum and Cheswick. The estimated cost for this project is $24 million, with a projected in-service date of December 2024. This project is identified as immediate need, and operating measures have been identified to mitigate reliability impacts in the interim. The local transmission owner, DL, will be designated to complete this work.

Baseline Project b3718: Data Center Alley Improvements

Dominion Transmission Zone

The Dominion zone has been experiencing load growth in the Data Center Alley area around Dulles airport. Forecasted data center additions for the 2022 Load Forecast provided by Dominion and NOVEC were noticeably higher than in the prior year. Due to the highly concentrated load growth in the Data Center Alley Area, numerous reliability violations (thermal overloads and load loss) were observed in the 2024 and 2025 time frames despite planned supplemental and baseline upgrades.

Map 16. **b3718 – Data Center Alley**



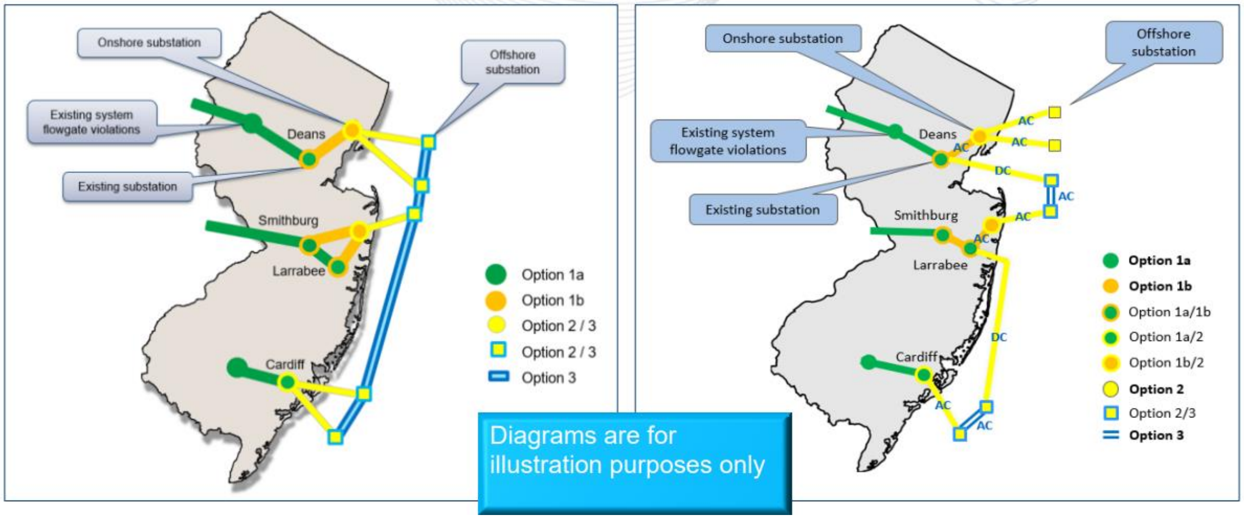
The recommended solution is to build a new 500/230 kV substation called Wishing Star near Brambleton substation and install one 500/230 kV 1440 MVA transformer at the substation. A new 500/230 kV substation called Mars will be built near Dulles International Airport, and one 500/230 kV 1440 MVA transformer will be installed at the substation. The 500 kV line No. 546 (Brambleton-Mosby) and 500 kV line No. 590 (Brambleton-Mosby) will be cut and extended to the proposed Wishing Star substation, and lines will terminate in a 500 kV breaker and a half configuration. The project will reconductor the approximate mileage of the following lines: 0.62 miles of 230 kV line No. 2214 (Buttermilk-Roundtable), 1.52 miles of 230 kV line No. 2031 (Enterprise-Greenway-Roundtable), 0.64 miles of 230 kV line No. 2186 (Enterprise-Shellhorn), 2.17 miles of 230 kV line No. 2188 (Lockridge-Greenway-Shellhorn), 0.84 miles of 230 kV line No. 2223 (Lockridge-Roundtable), 3.98 miles of 230 kV line No. 2218 (Sojourner-Runway-Shellhorn), and 1.61 miles of 230 kV line No. 9349 (Sojourner-Mars). The project will also upgrade four 500 kV breakers to 63 kA on either end of 500 kV line No. 584 (Loudoun-Mosby circuit No. 1) and four 500 kV breakers to 63 kA on either end of 500 kV line No. 502 (Loudoun-Mosby circuit No. 2), cut and loop the 230 kV line No. 2079 (Sterling Park-Dranesville) into the Davis Drive substation and install two GIS 230 kV breakers. The estimated cost for this project is $627.62 million. This project is identified as immediate need, with a required and projected in-service date of June 2025. The local transmission owner, Dominion, will be designated to complete this work.

Baseline Project b3737: NJ SAA Project

AE, BGE, JCPL, PECO, PPL & PSEG Transmission Zones

As part of the 2021 State Agreement Approach (SAA) Proposal Window to support New Jersey offshore wind, PJM received proposals to meet New Jersey's goal of interconnecting up to 7,500 MW of offshore wind. The proposals were categorized into four options according to the function and location of the proposal. Altogether, PJM received a diverse set of 80 proposals.

- **Option 1a proposals:** Onshore transmission upgrades to resolve potential reliability criteria violations on PJM facilities in accordance with all applicable planning criteria (PJM, NERC, SERC, RFC and local Transmission Owner criteria)
- **Option 1b proposals:** Onshore new transmission connection facilities
- **Option 2 proposals:** Offshore new transmission connection facilities
- **Option 3 proposals:** Offshore new transmission network facilities



Concepts depicted are for illustration purposes only.
Details of new lines and facilities are to be provided by sponsors in proposals to meet objectives of this solicitation.

Figure 1. Potential Options for the NJ Offshore Wind Transmission Solution

PJM worked with the NJ BPU to create offshore wind injection scenarios involving various combinations of the submitted Option 1b and Option 2 proposals. Each scenario contained the awarded solicitation No. 1 for 1,100 MW and solicitation No. 2 for 2,658 MW. While the scope for the submission of proposals did not allow alternative point of injections (POIs) for solicitation No. 1, it did allow alternative POIs for solicitation No. 2. As a result, each scenario contained identical considerations for solicitation No. 1, and the scenario creation focused on selecting combinations of submitted Option 1b and Option 2 proposals that together enable the transmission system to reliably deliver approximately 6,400 MW of additional offshore wind.

After the comprehensive reliability analysis and all other evaluations were complete, the NJ BPU selected Scenario 18a as the SAA Project. Scenario 18a uses JCPL Option 1b proposals 453.1–18, 24, 26–29 to interconnect 3,742 MW of offshore wind to central New Jersey, including 1,200 MW to Larrabee 230 kV, 1,200 MW to Atlantic 230 kV and 1,342 MW to Smithburg 500 kV. It also uses a portion of Mid-Atlantic Offshore Development (MAOD) proposal 551 to construct the Larrabee 230 kV AC Collector station and procure land adjacent to the MAOD AC switchyard for future HVDC converters.

The interconnection of the remaining 1,148 MW of solicitation No. 2 (Ocean Wind 2) offshore wind, 1,510 MW of solicitation No. 2 (Atlantic Shores 1) offshore wind, and the interconnection of the entire 1,100 MW of solicitation No. 1 (Ocean Wind 1) offshore wind are assumed to be the responsibility of the offshore wind developers.

JCPL Option 1b proposal 453.1–18, 24, 26–29 involves the following components:

- Rebuild the G1021 Atlantic-Smithburg 230 kV line from the Larrabee substation to the Smithburg substation as a double circuit 500/230 kV line
- Expand Smithburg 500 kV into a three-breaker ring bus for the offshore wind generation interconnection
- Expand Larrabee 230 kV with a new breaker-and-a-half layout, reterminating Larrabee to Lakewood 230 kV into the new terminal and constructing approximately 1,000 feet of new 230 kV line from the Larrabee station to an offshore wind 230 kV converter station
- Expand the Atlantic 230 kV bus and converting the substation to a new double-breaker bus with line exists for the offshore wind generators
- Construct new approximately 11.6-mile line from Atlantic substation to the offshore wind 230 kV converter station at Larrabee

- MAOD proposal 551 (partial) involves constructing the Larrabee 230 kV AC Collector station and procuring land adjacent to the MAOD AC switchyard for future HVDC converters. The below tables show a summary of costs by option components and the SAA Capability created by the selected SAA project:

Table 1. Scenario 18 Cost Summary

Scenario ID	Total (MW)	SAA (MW)	Proposing Entities	Option 1b		Option 2		Option 1a	TOTAL
				Proposal IDs	Cost Estimate ($M)	Proposal IDs	Cost Estimate ($M)	Cost Estimate ($M)	Cost Estimate ($M)

18a	6,400	3,742	JCPL, MAOD	453.1-18,24,27-29	$428	551 (partial)	$121	$515	$1,064

Table 2. Point of Interconnection & Associated Injected Amounts

Location	State	Transmission Owner	SAA Capability	MFO	MW Energy	MW Capacity
Larrabee Collector station 230 kV – Larrabee	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Atlantic	NJ	MAOD	1,200	1,200	1,200	360
Larrabee Collector station 230 kV – Smithburg	NJ	MAOD	1,342	1,342	1,342	402.6
Smithburg 500 kV	NJ	JCPL	1,148	1,148	1,148	327

The tables below show the Option 1b, 2 and 1a component cost estimates:

Table 3. Scenario 18a Option 1b Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	453.1	Atlantic 230 kV substation – Convert to double-breaker double-bus	$31.47
	453.2	Freneau substation – Update relay settings	$0.03
	453.3	Smithburg substation – Update relay settings	$0.03
	453.4	Oceanview substation – Update relay settings	$0.04
	453.5	Red Bank substation – Update relay settings	$0.04
	453.6	South River substation – Update relay settings	$0.03
	453.7	Larrabee substation – Update relay settings	$0.03
	453.8	Atlantic substation – Install line terminal	$4.95
	453.9	Larrabee substation – Reconfigure substation	$4.24
	453.10	Larrabee substation: 230 kV equipment for direct connection	$4.77
	453.11	Lakewood Gen substation – Update relay settings	$0.03
	453.12	G1021 (Atlantic-Smithburg) 230 kV	$9.68
	453.13	R1032 (Atlantic-Larrabee) 230 kV	$14.50
	453.14	New Larrabee Converter-Atlantic 230 kV	$17.07
	453.15	Larrabee-Oceanview 230 kV	$6.00
	453.16	B54 Larrabee-South Lockwood 34.5 kV line transfer	$0.31
	453.17	Larrabee Converter-Larrabee 230 kV new line	$7.52

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
	453.18	Larrabee Converter-Smithburg No. 1 500 kV line (new asset)	$150.35
	453.24	G1021 Atlantic-Smithburg 230 kV	$62.85
	453.26	D2004 Larrabee-Smithburg No1 230 kV	$44.77
	453.27	Smithburg substation 500 kV expansion	$5.81
	453.28	Larrabee substation	$0.86
	453.29	Smithburg substation 500 kV 3-breaker ring	$62.44
Total			**$427.82**

Table 4. Scenario 18a Option 2 Component Cost Estimates

<table>
<tr><th>Component Descriptions</th><th>In-Service Date (ISD)</th><th>Cost ($M)</th></tr>
<tr><td colspan="3">MAOD</td></tr>
<tr><td colspan="3">Proposal ID 551</td></tr>
<tr><td>Construct the AC switchyard portion of MAOD proposal 551, composed of a 230 kV 3 x breaker-and-a-half substation with a nominal current rating of 4000A and four single phase 500/230 kV 450 MVA autotransformers to step up the voltage for connection to the Smithburg substation. AC switchyard design and site preparation shall be suitable for expansion to a 230 kV 4 X 230 kV breaker-and-a-half substation and seven single phase 500/230 kV 450 MVA autotransformers to step up voltage for connection of two circuits to Smithburg substation.</td><td>ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work</td><td rowspan="2">$121.10
Note:
This cost represents a partial scope of MAOD proposal #551.
It excludes other owners' costs, permitting, commercial and financial fees, and will require further evaluation to refine the estimate.</td></tr>
<tr><td>Procure land adjacent to the MAOD AC switchyard, which is a portion of the MAOD proposal 551, and prepare the site for construction of future AC to DC converters for future interconnection of DC circuits from offshore wind generation. Land should be suitable to accommodate installation of four individual converters to accommodate circuits with equivalent rating of 1400 MVA at 400 kV. MAOD will commit to work with NJBPU and staff, PJM, the relevant transmission owners, and all future developers to lease or otherwise make land access available for construction of converters by those developers to support the integration of OSW generators to achieve the OSW goals of New Jersey.</td><td>ISD to be aligned with NJBPU solicitation schedule and related JCPL Proposal 453 project work</td></tr>
</table>

Table 5. Scenario 18a Option 1a Component Cost Estimates

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.4–17.11	Convert the six-wired East Windsor-Smithburg E2005 230 kV line (9.0 mi.) to two circuits. One a 500 kV line and the other a 230 kV line.	**$206.48**

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
JCPL	17.18	Add third Smithburg 500/230 kV	**$13.40**
PPL	330	Reconductor Gilbert-Springfield 230 kV	**$0.38**
JCPL	17.16	Reconductor Clarksville-Lawrence 230 kV	**$11.45**
PSEG	PPT 3/11/2022	Upgrade Lake Nelson I 230 kV	**$3.80**
JCPL	17.19	Reconductor Kilmer I-Lake Nelson I 230 kV	**$4.42**
PSEG	PPT 2/4/2022	Upgrade Lake Nelson W 230 kV	**$0.16**
JCPL	Email 12/30/2021	Additional reconductoring required For Lake Nelson I-Middlesex 230 kV	**$3.30**
PSEG	180.3, 180.4, 180.7	Linden & Bergen subprojects	**$30.45**
PSEG	PPT 2/4/2022	Upgrade Greenbrook W 230 kV	**$0.12**
JCPL	Email 2/11/2022	Reconductor small section of Raritan River-Kilmer I 230 kV (n6201)	**$0.20**
JCPL	Email 2/11/2022	Replace substation conductor at Kilmer & reconductor Raritan River-Kilmer W 230 kV (n6202)	**$25.88**
JCPL	Email 2/11/2022	Reconductor Red Oak A-Raritan River 230 kV (n6203)	**$11.05**
JCPL	Email 2/11/2022	Reconductor Red Oak B-Raritan River 230 kV (n6204)	**$3.90**
AE	127.10	Reconductor Richmond-Waneeta 230 kV	**$16.00**
PSEG	180.5, 180.6	Windsor to Clarksville subproject	**$5.77**
AE	127.1	Upgrade Cardiff-Lewis 138 kV	**$0.10**
AE	127.3	Upgrade Cardiff-New Freedom 230 kV	**$0.30**

Proposing Entity	Proposal IDs	Components	Proposal Cost ($M)
AE	127.2	Upgrade Lewis No. 2-Lewis No. 1 138 kV	**$0.50**
CNTLM	229	One additional Hope Creek-Silver Run 230 kV submarine cables and rerate plus upgrade line	**$61.20**
Transource	63	North Delta Option A	**$109.68**
PECO	Incumbent TO	Replace four Peach Bottom 500 kV breakers	**$5.60**
BGE	Incumbent TO	Upgrade one Conastone 230 kV breaker	**$1.30**
TOTAL			**$515.44**

The total estimated cost for this project is $1,064.36 million, with various required in-service dates ranging from December 2027 through June 2030 to align with New Jersey's solicitation schedule. The designated entities that proposed the projects and the local transmission owners, AE, BGE, JCPL, LS Power, MAOD, PECO, PPL, PSEG and Transource, will be designated to complete this work.

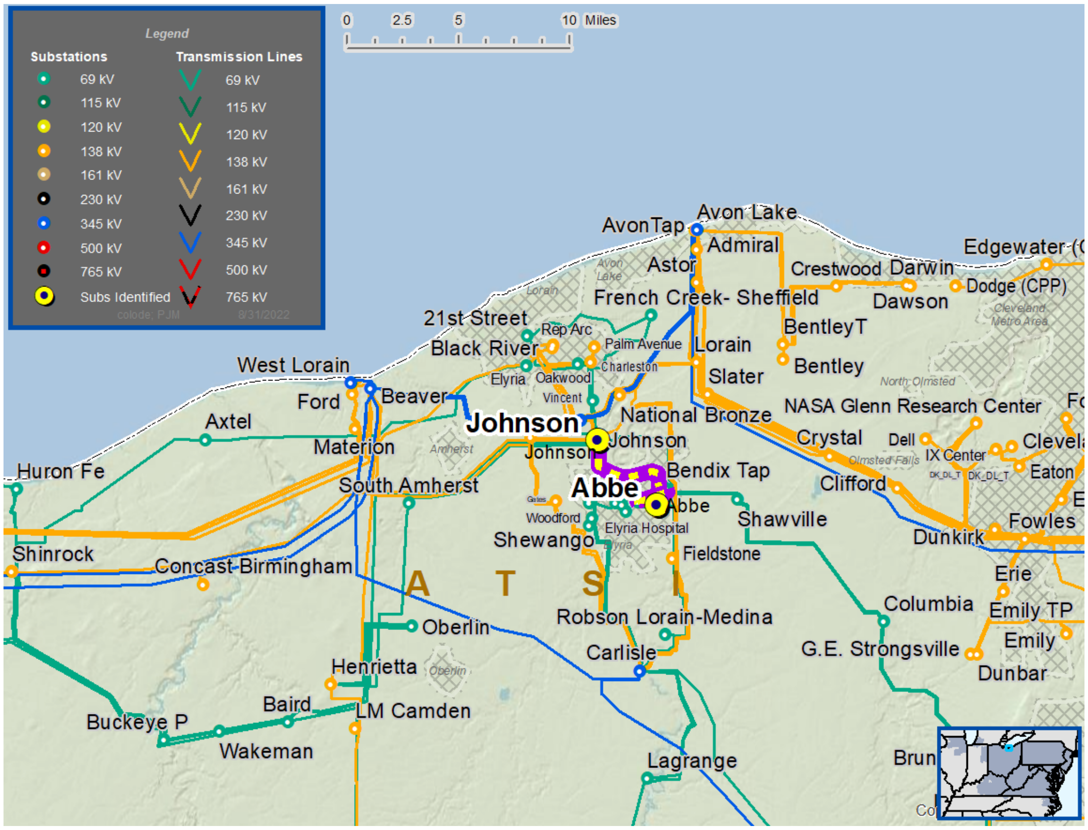
For additional details regarding the NJ SAA project, please refer to the Nov. 4, 2022, special TEAC presentation and the reports posted with the meeting materials: https://pjm.com/committees-and-groups/committees/teac.aspx

Baseline Project b3720: Abbe-Johnson 69 kV Rebuild

ATSI Transmission Zone

In the 2027 RTEP summer case, the Abbe-Johnson 69 kV line is overloaded for an N-1 outage combination. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 17. b3720 – Abbe-Johnson 69 kV



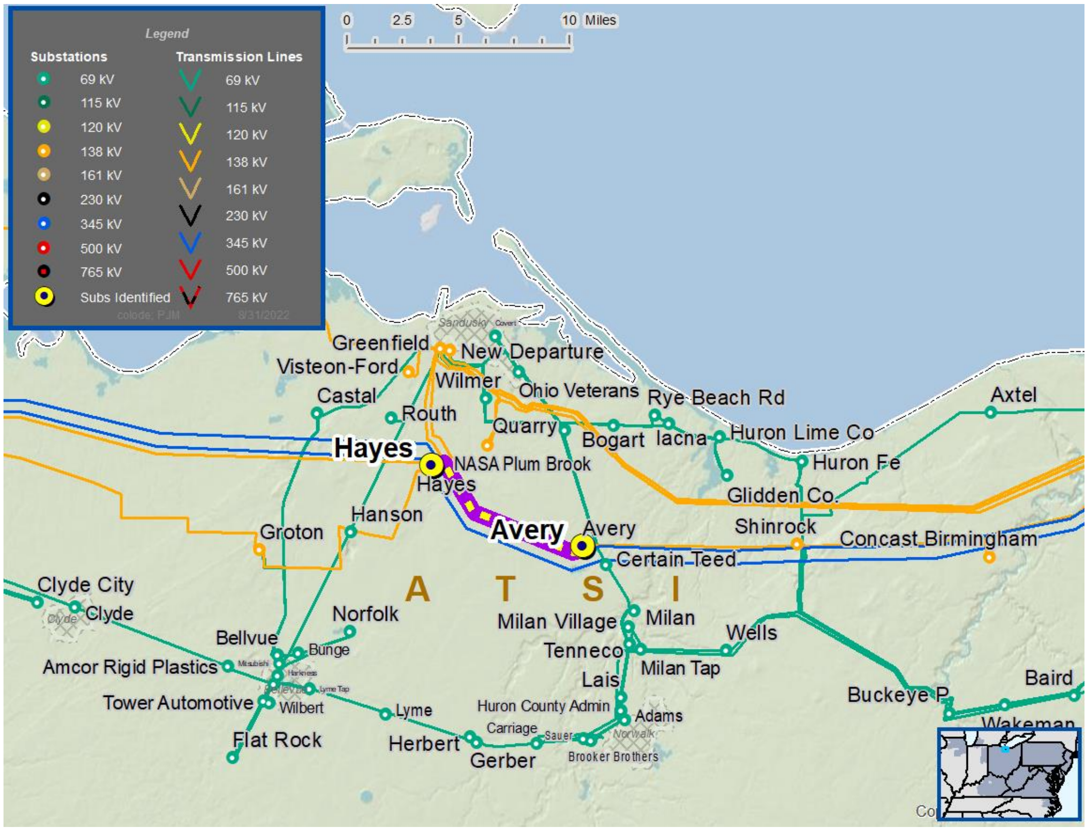
The recommended solution is to rebuild the Abbe-Johnson No. 2 69 kV line (approx. 4.9 miles) with 556 kcmil ACSR conductor. The project will also replace three disconnect switches (A17, D15 and D16), replace line drops and revise relay settings at Abbe substation; replace one disconnect switch (A159), replace line drops and revise relay settings at Johnson substation; and replace two motor-operated airbreak disconnect switches (A4 & A5), one disconnect switch (D9) and line drops at Redman substation. The estimated cost for this project is $10.9 million. This project has a required in-service date of June 2027 and a projected in-service date of June 2026. The local transmission owner, ATSI, will be designated to complete this work.

Baseline Project b3721: Avery-Hayes 138 kV Rebuild and Reconductor

ATSI Transmission Zone

In the 2027 RTEP summer case, the Avery-Hayes 138 kV line is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 18. **b3721 – Avery-Hayes 138 kV**



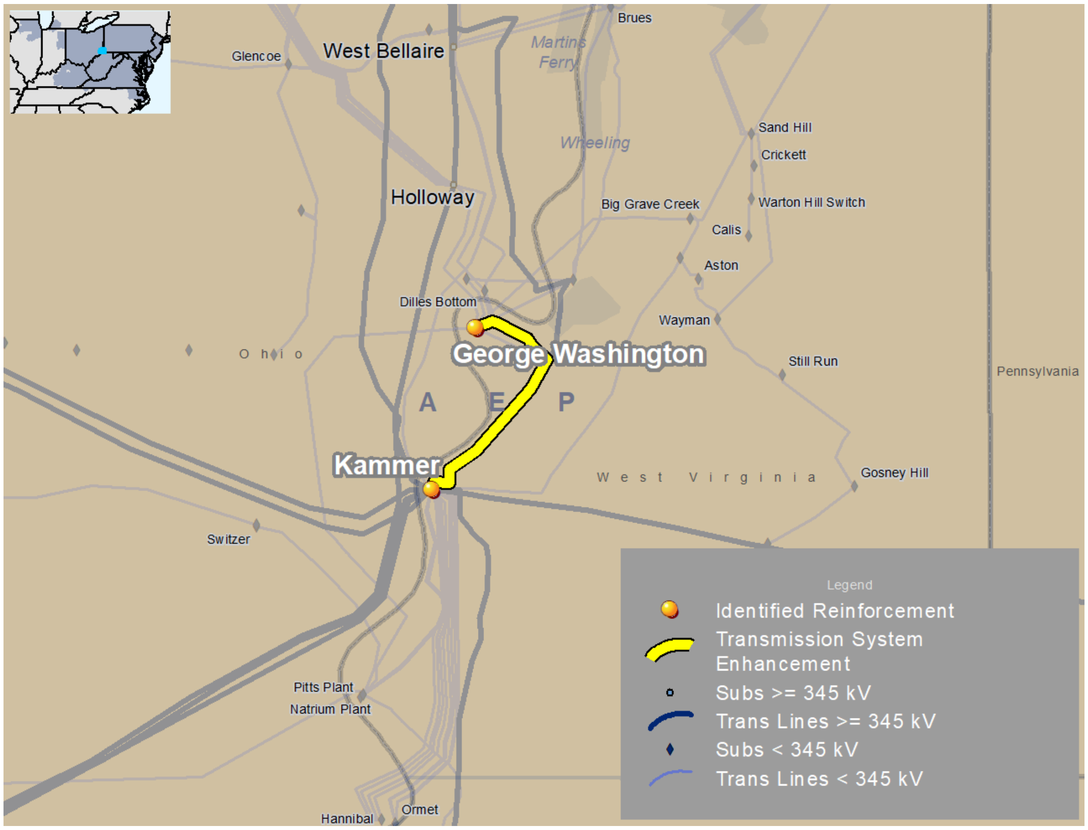
The recommended solution is to rebuild and reconductor the Avery-Hayes 138 kV line (approx. 6.5 miles) with 795 kcmil 26/7 ACSR. The estimated cost for this project is $10.4 million, with a required and projected in-service date of June 2027. The local transmission owner, ATSI, will be designated to complete this work.

Baseline Project b3723: George Washington-Kammer 138 kV Rebuild

AEP Transmission Zone

In the 2027 RTEP summer case, the George Washington-Kammer 138 kV line is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1 but was excluded from competition due to the below 200 kV exclusion.

Map 19. **b3723 – George Washington-Kammer 138 kV**



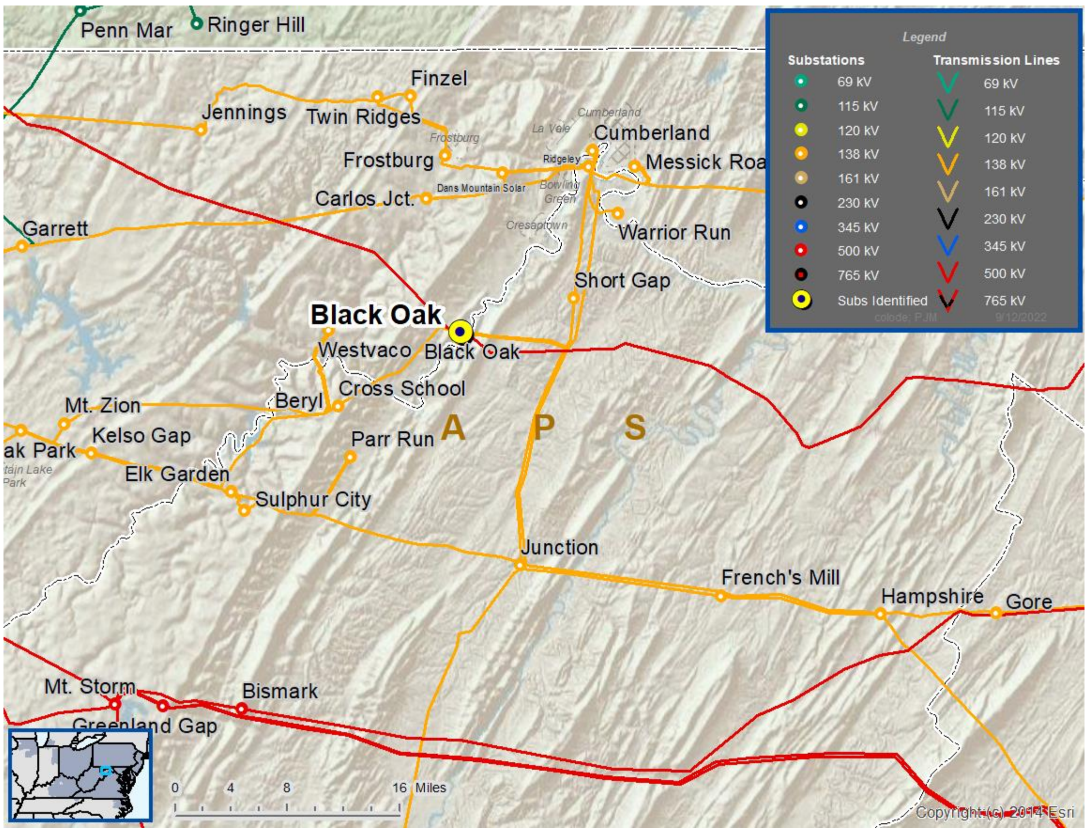
The recommended solution is to rebuild the George Washington-Kammer 138 kV line (6.7 miles of total upgrade scope). The project will also remove the existing six-wired steel lattice towers and supplement the right-of-way as needed. The estimated cost for this project is $18.3 million. This project has a required in-service date of June 2027 and a projected in-service date of June 2024. The local transmission owner, AEP, will be designated to complete this work.

Baseline Project b3726: Black Oak 500 kV Substation Improvements

APS Transmission Zone

In the 2027 RTEP summer and winter case, there are several voltage drop violations at the Black Oak 500 kV substation for N-1 outage combinations. The flow gates were posted as part of 2022 RTEP Window 1, and PJM received one proposal to address the flow gates.

Map 20. **b3726 – Black Oak 500 kV**



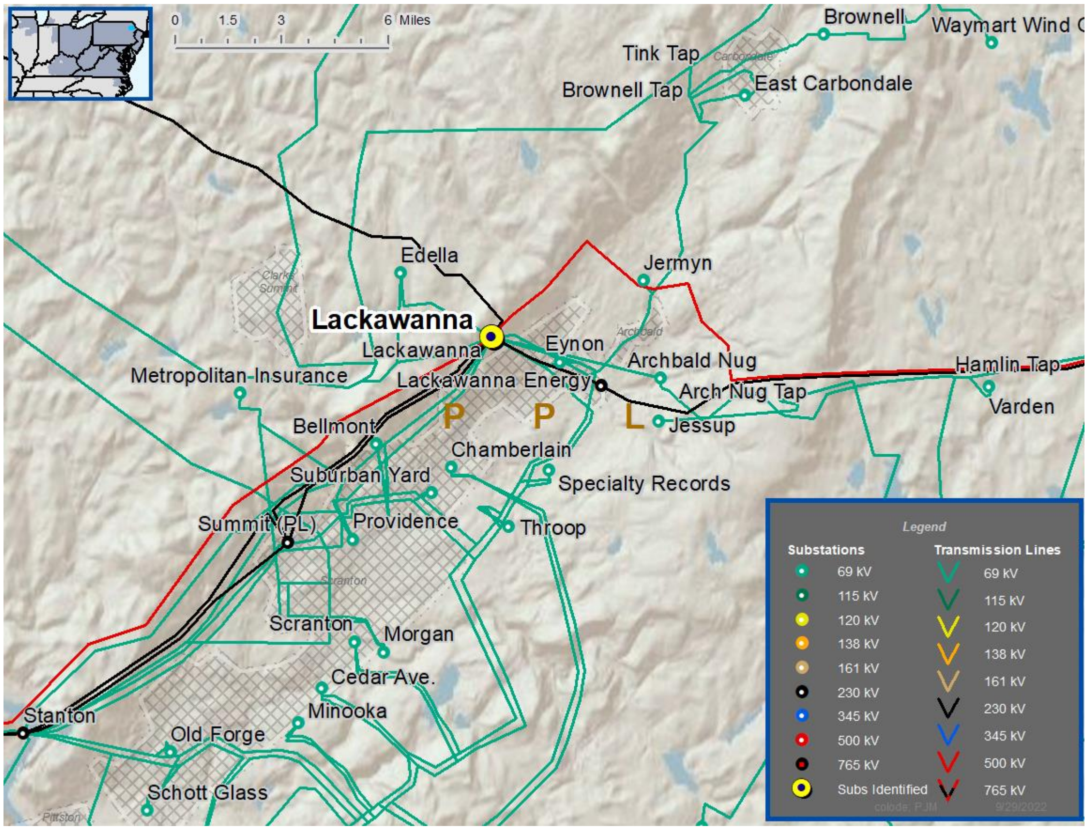
The recommended solution is to install two new 500 kV 50 kA breakers on the existing open SVC string to create a new bay position, and relocate and reterminate facilities as necessary to move the 500 kV SVC into the new bay position. The project will also install a 500 kV 50 kA breaker on the 500/138 kV No. 3 transformer, and upgrade relaying at Black Oak substation. The estimated cost for this project is $17.37 million, with a required and projected in-service date of June 2027. The local transmission owner, APS, will be designated to complete this work.

Baseline Project b3730: Lackawanna 500/230 kV Transformer Improvements

PPL Transmission Zone

In the 2027 RTEP summer case, the Lackawanna No. T3 transformer is overloaded for an N-2 outage. The flow gate was posted as part of 2022 RTEP Window 1, and PJM received three proposals to address the flow gate.

Map 21. **b3730 – Lackawanna 500/230 kV**



The recommended solution is to reterminate the Lackawanna T3 and T4 500/230 kV transformers on the 230 kV side to remove them from the 230 kV buses and bring them into dedicated bay positions that are not adjacent to one another. The estimated cost for this project is $10.7 million. This project has a required in-service date of June 2027 and a projected in-service date of January 2026. The local transmission owner, PPL, will be designated to complete this work.

Appendix A - Previously Identified RTEP Baseline Upgrades

Appendix A contains all currently required baseline upgrades that were identified in previous RTEP assessments. This appendix also contains expected required in-service dates for facilities. PJM continuously evaluates the lead times of these plans with respect to the expected required in-service dates. The continuing need for these required system facilities was evaluated as part of the 2022 RTEP assessment and will be evaluated in future RTEP assessments. This list of upgrades represents a snapshot of all required planned facilities in the RTEP as of 12/31/2022.

1) Baseline Upgrade b0866
- Replace Chalk Point 230 kV breaker (6C) with 80 Ka breaker - 6/1/2012 - $2.00M

2) Baseline Upgrade b1270
- Reconductor Bath - Trebein 138kV - 6/1/2015 - $1.30M

3) Baseline Upgrade b1273
- Add 2nd Bath 345/138kV Xfr - 6/1/2015 - $7.00M

4) Baseline Upgrade b1274
- Add 2nd Trebein 138/69kV Xfr - 6/1/2015 - $5.30M

5) Baseline Upgrade b1275
- Add 2nd W. Milton 138/69kV Xfr - 6/1/2015 - $8.80M

6) Baseline Upgrade b1276
- Add 2nd W. Milton 345/138 Xfr - 6/1/2015 - $5.50M

7) Baseline Upgrade b1570
- Add a 345/69 kV transformer at Dayton's Peoria 345 kV bus - 6/1/2014 - $16.00M

8) Baseline Upgrade b1570.1
- Add/reconductor Peoria - Darby 69 kV line - 6/1/2014 - $0.00M

9) Baseline Upgrade b1570.2
- Add / reconductor Peoria - Union REA 69 kV line - 6/1/2014 - $0.00M

10) Baseline Upgrade b1570.3
- Reconductor Union REA - Honda MT 69 kV line - 6/1/2014 - $0.00M

11) Baseline Upgrade b1572
- Construct a new 138 kV line from West Milton to Eldean - 6/1/2014 - $16.00M

12) Baseline Upgrade b1696
- Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV - 5/1/2016 - $159.00M

13) Baseline Upgrade b1696.2
- Replace the Idylwood 230 kV '209712' breaker with 50 kA breaker - 6/1/2017 - $0.35M

14) Baseline Upgrade b2003

- Construct a Whippany to Montville 230 kV line (6.4 miles) - 6/1/2015 - $80.60M

15) Baseline Upgrade b2220

- Install two 115 kV breakers at Chestnut Hill and remove sag limitations on the Pumphrey - Frederick Rd 115 kV circuits 110527 and 110528 to obtain a 125 deg. Celsius rating (161/210 MVA) - 6/1/2017 - $14.00M

16) Baseline Upgrade b2257

- Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations - 6/1/2017 - $84.70M

17) Baseline Upgrade b2361

- Construct a 230kV UG line approx. 4.5 miles from Idylwood to Tysons. Tysons Substation will be rebuilt, within its existing footprint, with a 6-breaker ring bus using GIS equipment. - 6/1/2017 - $210.00M

18) Baseline Upgrade b2436.90

- Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades - 6/1/2015 - $40.21M

19) Baseline Upgrade b2443.6

- Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed. - 6/1/2026 - $23.08M

20) Baseline Upgrade b2555

- Updated scope: Reconductor 0.3 miles of Tiltonsville-Windsor 138 kV into Tiltonsville station with 795 ACSS; string the vacant side of the 3.8 mile middle section using 556 ACSR and operate in a six wire configuration; rebuild the 0.9 mile section crossing from Ohio into the Windsor station in West Virginia, using 795 ACSS. - 6/1/2019 - $2.00M

21) Baseline Upgrade b2597

- Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch - 6/1/2019 - $2.15M

22) Baseline Upgrade b2598

- Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street. - 6/1/2019 - $1.69M

23) Baseline Upgrade b2604.1

- Remove approximately 11.32 miles of the 69 kV line between Millbrook Park and Franklin Furnace. - 6/1/2019 - $1.13M

24) Baseline Upgrade b2604.10

- Build a new station (Althea) with a 138/69 kV, 90 MVA transformer. The 138 kV side will have a single 2000 A 40 kA circuit breaker and the 69 kV side will be a 2000 A 40 kA three breaker ring bus. - 6/1/2019 - $11.07M

25) Baseline Upgrade b2604.11

- Remote end work at Hanging Rock, East Wheelersburg and North Haverhill 138 kV. - 6/1/2019 - $0.06M

26) Baseline Upgrade b2604.2

- At Millbrook Park station, add a new 138/69 kV transformer #2 (90 MVA) with 3000 A 40 kA breakers on the high and low side. Replace the 600 A MOAB Switch and add a 3000 A circuit switcher on the high side of transformer #1. - 6/1/2019 - $3.05M

27) Baseline Upgrade b2604.3

- Replace Sciotoville 69 kV station with a new 138/12 kV in-out station (Cottrell) with 2000A line MOABs facing Millbrook Park and East Wheelersburg 138 kV. - 6/1/2019 - $1.40M

28) Baseline Upgrade b2604.4

- Tie Cottrell switch into the Millbrook Park-East Wheelersburg 138 kV circuit by constructing 0.50 miles of line using 795 ACSR 26/7 Drake (SE 359 MVA). - 6/1/2019 - $1.96M

29) Baseline Upgrade b2604.5

- Install a new 2000 A 3-way POP Switch outside of Texas Eastern 138 kV substation (Sadiq Switch). - 6/1/2019 - $1.08M

30) Baseline Upgrade b2604.6

- Replace the Wheelersburg 69 kV station with a new 138/12 kV in-out station (Sweetgum) with a 3000 A 40 kA breaker facing Sadiq Switch and a 2000 A 138 kV MOAB facing Althea. - 6/1/2019 - $2.16M

31) Baseline Upgrade b2604.7

- Build approximately 1.4 miles of new 138 kV line using 795 ACSR 26/7 Drake (SE 359 MVA) between the new Sadiq Switch and the new Sweetgum 138 kV stations. - 6/1/2019 - $3.41M

32) Baseline Upgrade b2604.8

- Remove the existing 69 kV Hayport Road Switch. - 6/1/2019 - $0.10M

33) Baseline Upgrade b2604.9

- Rebuild approximately 2.3 miles along existing ROW from Sweetgum to the Hayport Rd switch 69 kV location as 138 kV single circuit and rebuild approximately 2.0 miles from the Hayport Road switch to Althea 69 kV with double circuit 138 kV construction, one side operated at 69 kV to continue service to K.O. Wheelersburg, using 795 ACSR 26/7 Drake (SE 359 MVA). - 6/1/2019 - $10.76M

34) Baseline Upgrade b2633

- Artificial Island Solution - 4/1/2019 - $0.00M

35) Baseline Upgrade b2633.91

- Implement changes to the tap settings for the two Salem units' step up transformers - 4/1/2019 - $0.01M

36) Baseline Upgrade b2633.92

- Implement changes to the tap settings for the Hope Creek unit's step up transformers - 4/1/2019 - $0.01M

37) Baseline Upgrade b2668.1

- Replace the bus/risers at Dequine 345 kV station - 6/1/2020 - $2.30M

38) Baseline Upgrade b2708

- Replace the Oceanview 230/34.5 kV transformer #1 - 6/1/2020 - $4.07M

39) Baseline Upgrade b2743.1

- Tap the Conemaugh - Hunterstown 500 kV line & create new Rice 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $43.10M

40) Baseline Upgrade b2743.2

- Tie in new Rice substation to Conemaugh-Hunterstown 500 kV - 6/1/2020 - $14.60M

41) Baseline Upgrade b2743.3

- Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.35M

42) Baseline Upgrade b2743.4

- Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit - 6/1/2020 - $0.20M

43) Baseline Upgrade b2743.5

- Build new 230 kV double circuit line between Rice and Ringgold 230 kV, operated as a single circuit. - 6/1/2020 - $93.40M

44) Baseline Upgrade b2743.6

- Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme - 6/1/2020 - $7.87M

45) Baseline Upgrade b2743.6.1

- Replace the two Ringgold 230/138 kV transformers - 6/1/2020 - $6.26M

46) Baseline Upgrade b2743.7

- Rebuild/Reconductor the Ringgold - Catoctin 138 kV circuit and upgrade terminal equipment on both ends - 6/1/2020 - $47.22M

47) Baseline Upgrade b2743.8

- Replace Ringgold Substation 138 kV breakers '138 BUS TIE' and 'RCM0' with 40 kA breakers - 6/1/2020 - $0.71M

48) Baseline Upgrade b2752.1

- Tap the Peach Bottom – TMI 500 kV line & create new Furnace Run 500 kV & 230 kV stations. Install two 500/230 kV transformers, operated together. - 6/1/2020 - $39.80M

49) Baseline Upgrade b2752.2

- Tie in new Furnace Run substation to Peach Bottom-TMI 500 kV - 6/1/2020 - $10.50M

50) Baseline Upgrade b2752.3

- Upgrade terminal equipment and required relay communication at Peach Bottom 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $1.70M

51) Baseline Upgrade b2752.4

- Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Peach Bottom - TMI 500 kV circuit - 6/1/2020 - $2.00M

52) Baseline Upgrade b2752.5

- Build new 230 kV double circuit line between Furnace Run and Conastone 230 kV, operated as a single circuit. - 6/1/2020 - $51.12M

53) Baseline Upgrade b2752.6

- Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit) - 6/1/2020 - $6.14M

54) Baseline Upgrade b2752.7

- Reconductor/Rebuild the two Conastone - Northwest 230 kV lines and upgrade terminal equipment on both ends - 6/1/2020 - $52.14M

55) Baseline Upgrade b2752.8

- Replace the Conastone 230kV '2322 B5' breaker with a 63kA breaker - 6/1/2020 - $1.51M

56) Baseline Upgrade b2752.9

- Replace the Conastone 230kV '2322 B6' breaker with a 63kA breaker - 6/1/2020 - $1.51M

57) Baseline Upgrade b2753.7

- Retire line sections (Dilles Bottom - Bellaire and Moundsville - Dilles Bottom 69 kV lines) south of First Energy 138 kV line corridor, near “Point A”. Tie George Washington - Moundsville 69 kV circuit to George Washington - West Bellaire 69 kV circuit. - 5/31/2020 - $5.52M

58) Baseline Upgrade b2759

- Rebuild Line #550 Mt. Storm – Valley 500kV - 6/1/2016 - $476.00M

59) Baseline Upgrade b2760

- Perform a Sag Study of the Saltville - Tazewell 138 kV line to increase the thermal rating of the line - 6/1/2021 - $0.10M

60) Baseline Upgrade b2765

- Upgrade bus conductor at Gardners 115 kV substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV - 6/1/2021 - $1.20M

61) Baseline Upgrade b2791

- Rebuild Tiffin-Howard, new transformer at Chatfield - 6/1/2021 - $20.39M

62) Baseline Upgrade b2791.3

- New 138/69kV transformer with 138kV & 69kV protection at Chatfield station. - 6/1/2021 - $0.00M

63) Baseline Upgrade b2791.4

- New 138kV & 69kV protection at existing Chatfield transformer. - 6/1/2021 - $2.50M

64) Baseline Upgrade b2793

- Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading. - 6/1/2021 - $1.30M

65) Baseline Upgrade b2891

- Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area. - 6/1/2021 - $13.40M

66) Baseline Upgrade b2914

- Rebuild Tharp Tap-KU Elizabethtown 69kV line section to 795 MCM (2.11 miles). - 12/1/2024 - $1.22M

67) Baseline Upgrade b2932

- Replace terminal equipment at Tanners Creek on Tanners Creek Dearborn 345 kV line. - 6/1/2021 - $1.50M

68) Baseline Upgrade b2933

- Third Source for Springfield Rd. and Stanley Terrace Stations - 6/1/2018 - $0.00M

69) Baseline Upgrade b2933.31

- Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Front Street - Springfield) - 6/1/2018 - $39.66M

70) Baseline Upgrade b2935

- Third Supply for Runnemede 69kV and Woodbury 69kV - 6/1/2018 - $90.60M

71) Baseline Upgrade b2935.1

- Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line. - 6/1/2018 - $0.00M

72) Baseline Upgrade b2935.2

- Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply - 6/1/2018 - $0.00M

73) Baseline Upgrade b2938

- Perform a sag mitigations on the Broadford – Wolf Hills 138kV circuit to allow the line to operate to a higher maximum temperature. - 6/1/2022 - $2.60M

74) Baseline Upgrade b2940

- Upgrade the distance relay on the Wayne Co – Wayne Co KY 161kV line to increase the line winter rating would be 167/167 - 12/1/2022 - $0.00M

75) Baseline Upgrade b2945.1

- Rebuild the BL England – Middle Tap 138kV line to 2000A on double circuited steel poles and new foundations - 6/1/2022 - $52.20M

76) Baseline Upgrade b2945.2

- Re-conductor BL England – Merion 138kV (1.9miles) line - 6/1/2022 - $3.73M

77) Baseline Upgrade b2945.3

- Re-conductor Merion – Corson 138kV (8miles) line - 6/1/2022 - $8.36M

78) Baseline Upgrade b2946

- Convert existing Preston 69 kV Substation to DPL's current design standard of a 3-breaker ring bus. - 6/1/2022 - $6.67M

79) Baseline Upgrade b2947.1

- Upgrade terminal equipment at DPL's Naamans Substation (Darley-Naamans 69 kV) - 6/1/2022 - $0.38M

80) Baseline Upgrade b2950

- Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay - 6/1/2022 - $0.25M

81) Baseline Upgrade b2970

- Ringgold - Catoctin Solution - 6/1/2020 - $0.00M

82) Baseline Upgrade b2970.1

- Install two new 230 kV positions at Ringgold for 230/138 kV transformers. - 6/1/2020 - $3.20M

83) Baseline Upgrade b2970.2

- Install new 230 kV position for the Catoctin 230 kV line at Ringgold. - 6/1/2020 - $1.60M

84) Baseline Upgrade b2970.3

- Install one new 230 kV breaker at Catoctin substation. - 6/1/2020 - $7.60M

85) Baseline Upgrade b2970.4

- Install new 230 / 138 kV transformer at Catoctin substation. Convert Ringgold-Catoctin 138 kV Line to 230 kV operation. - 6/1/2020 - $0.90M

86) Baseline Upgrade b2970.5

- Convert Garfield 138/12.5 kV substation to 230/12.5 kV - 6/1/2020 - $2.20M

87) Baseline Upgrade b2981

- Rebuild 115 kV Line No.29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV) - 12/31/2022 - $19.24M

88) Baseline Upgrade b2986.1

- Roseland-Branchburg 230kV corridor rebuild - 6/1/2018 - $0.00M

89) Baseline Upgrade b2986.11

- Roseland-Branchburg 230kV corridor rebuild (Roseland - Readington) - 6/1/2018 - $292.18M

90) Baseline Upgrade b2986.12

- Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) - 6/1/2018 - $55.29M

91) Baseline Upgrade b2986.2

- Branchburg-Pleasant Valley 230kV corridor rebuild - 6/1/2018 - $0.00M

92) Baseline Upgrade b2986.22

- Branchburg-Pleasant Valley 230kV corridor rebuild (East Flemington - Pleasant Valley) - 6/1/2018 - $108.12M

93) Baseline Upgrade b2986.23

- Branchburg-Pleasant Valley 230kV corridor rebuild (Pleasant Valley - Rocktown) - 6/1/2018 - $21.73M

94) Baseline Upgrade b2986.24

- Branchburg-Pleasant Valley 230kV corridor rebuild (the PSEG portion of Rocktown - Buckingham) - 6/1/2018 - $9.18M

95) Baseline Upgrade b2987

- Install a 30 MVAR capacitor bank at DPL's Cool Springs 69 kV Substation. The capacitor bank would be installed in two separate 15 MVAR stages allowing DPL operational flexibility - 6/1/2022 - $3.65M

96) Baseline Upgrade b3005

- Reconductor 3.1 mile 556 ACSR portion of Cabot to Butler 138 kV with 556 ACSS and upgrade terminal equipment. 3.1 miles of line will be reconductored for this project. The total length of the line is 7.75 miles. - 6/1/2021 - $5.88M

97) Baseline Upgrade b3007.1

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - AP portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Social Hall, meters, relays, bus conductor, a wavetrap, circuit breaker and disconnects will be replaced. - 6/1/2021 - $4.42M

98) Baseline Upgrade b3007.2

- Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - PENELEC portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Blairsville East, the wave trap and breaker disconnects will be replaced. - 6/1/2021 - $7.00M

99) Baseline Upgrade b3010

- Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wavetrap, and meter will be replaced. At Cabot, a wavetrap and bus conductor will be replaced. - 6/1/2021 - $0.78M

100) Baseline Upgrade b3011.1

- Construct new Route 51 substation and connect 10 138 kV lines to new substation - 6/1/2021 - $36.34M

101) Baseline Upgrade b3011.6

- Upgrade remote end relays for Yukon –Allenport – Iron Bridge 138 kV line - 6/1/2021 - $1.97M

102) Baseline Upgrade b3012.1

- Construct two new 138 kV ties with the single structure from APS's new substation to DUQ's new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase. - 6/1/2021 - $23.10M

103) Baseline Upgrade b3012.3

- Construct a new Elrama - Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation. - 6/1/2020 - $18.10M

104) Baseline Upgrade b3013

- Reconductor Vasco Tap to Edgewater Tap 138 kV line. 4.4 miles. The new conductor will be 336 ACSS replacing the existing 336 ACSR conductor. - 6/1/2021 - $5.88M

105) Baseline Upgrade b3014

- Replace the existing Shelocta 230/115 kV transformer and construct a 230 kV ring bus - 6/1/2021 - $7.35M

106) Baseline Upgrade b3015.8

- Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line - 6/1/2021 - $2.00M

107) Baseline Upgrade b3017.1

- Rebuild Glade to Warren 230 kV line with hi-temp conductor and substation terminal upgrades. 11.53 miles. New conductor will be 1033 ACSS. Existing conductor is 1033 ACSR. - 6/1/2021 - $42.40M

108) Baseline Upgrade b3017.2

- Glade substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

109) Baseline Upgrade b3017.3

- Warren substation terminal upgrades. Replace bus conductor, wave traps, and relaying. - 6/1/2021 - $0.05M

110) Baseline Upgrade b3019.1

- Update the nameplate for Morrisville 500 kV breaker "H1T594" to be 50 kA - 6/1/2018 - $0.00M

111) Baseline Upgrade b3019.2

- Update the nameplate for Morrisville 500 kV breaker "H1T545" to be 50 kA - 6/1/2018 - $0.00M

112) Baseline Upgrade b3020

- Rebuild 500kV Line #574 Ladysmith to Elmont - 26.2 miles long - 6/1/2018 - $91.32M

113) Baseline Upgrade b3021

- Rebuild 500kV Line #581 Ladysmith to Chancellor - 15.2 miles long - 6/1/2018 - $44.38M

114) Baseline Upgrade b3023

- Replace West Wharton 115kV breakers 'G943A' and 'G943B' with 40kA breakers - 6/1/2020 - $0.50M

115) Baseline Upgrade b3025

- Construct two (2) new 69/13kV stations in the Doremus area and relocate the Doremus load to the new stations - 6/1/2018 - $96.60M

116) Baseline Upgrade b3025.2

- Install a new 69/13 kV station (area of 19th Ave) with a ring bus configuration - 6/1/2018 - $0.00M

117) Baseline Upgrade b3025.3

- Construct a 69kV network between Stanley Terrace, Springfield Road, McCarter, Federal Square, and the two new stations (Vauxhall & area of 19th Ave) - 6/1/2018 - $0.00M

118) Baseline Upgrade b3029

- Install 69 kV underground transmission line from Harings Corner Station terminating at Closter Station (about 3 miles). - 5/31/2020 - $22.00M

119) Baseline Upgrade b3029.1

- Reconfigure Closter Station to accommodate the UG transmission line from Harings Corner Station - 5/31/2020 - $0.00M

120) Baseline Upgrade b3029.2

- Loop in the existing 751 Line (Sparkill - Cresskill 69 kV) into Closter 69 kV station - 5/31/2020 - $0.00M

121) Baseline Upgrade b3031

- Transfer load off of the Leroy Center-Mayfield Q2 138 kV line by reconfiguring the Pawnee Substation primary source, via the existing switches, from the Leroy Center-Mayfield Q2 138 kV line to the Leroy Center-Mayfield Q1 138 kV line. - 6/1/2021 - $0.10M

122) Baseline Upgrade b3033

- Ottawa-Lakeview 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $20.00M

123) Baseline Upgrade b3034

- Lakeview-Greenfield 138 kV Reconductor and Substation Upgrades - 12/1/2023 - $4.80M

124) Baseline Upgrade b3037

- Upgrades at the Natrium substation - 6/1/2023 - $1.10M

125) Baseline Upgrade b3039

- Line Swaps at Muskingum 138 kV Station - 12/1/2023 - $0.10M

126) Baseline Upgrade b3041

- Peach Bottom - Furnace Run 500kV Terminal Equipment - 6/1/2021 - $3.50M

127) Baseline Upgrade b3042

- Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal - 6/1/2023 - $0.05M

128) Baseline Upgrade b3050

- Install redundant relay to Port Union 138 kV Bus#2 - 6/1/2023 - $0.39M

129) Baseline Upgrade b3053

- Upgrade terminal equipment on Gibson - Petersburg 345kV - 10/29/2018 - $4.30M

130) Baseline Upgrade b3054

- Install a battery storage device at Grasonville Substation * Rebuild Wye Mills - Stevensville 69 kV Line * Construct a new 69 kV line from Wye Mills to Grasonville. - 12/1/2023 - $0.00M

131) Baseline Upgrade b3055

- Install spare 230/69 kV transformer at Davis Substation - 6/1/2023 - $0.54M

132) Baseline Upgrade b3056

- Partial Rebuild 230 kV Line #2113 Waller to Lightfoot - 6/1/2018 - $9.00M

133) Baseline Upgrade b3057

- Rebuild 6.1 miles of Waller-Skiffess Creek 230 kV Line (#2154) between Waller and Kings Mill to current standards with a minimum summer emergency rating of 1047 MVA utilizing single circuit steel structures. Remove this 6.1 mile section of Line #58 between Waller and Kings Mill. Rebuild the 1.6 miles of Line #2154 and #19 between Kings Mill and Skiffes Creek to current standards with a minimum summer emergency rating of 1047 MVA at 230 kV for Line #2154 and 261 MVA at 115 kV for Line #19, utilizing double circuit steel structures. - 6/1/2018 - $18.36M

134) Baseline Upgrade b3058

- Partial Rebuild of 230 kV lines between Clifton and Johnson DP (#265, #200 and #2051) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2018 - $11.50M

135) Baseline Upgrade b3064.3

- Upgrade line relaying at Piney Fork and Bethel Park for Piney Fork – Elrama 138 kV line and Bethel Park – Elrama 138 kV line. - 6/1/2021 - $0.60M

136) Baseline Upgrade b3066

- Reconductor the Cranberry - Jackson 138 kV line (2.1 miles), reconductor 138 kV bus at Cranberryand replace 138 kv line switches at Jackson - 6/1/2022 - $2.90M

137) Baseline Upgrade b3067

- Reconductor the Jackson - Maple 138 kV line (4.7 miles), replace line switches at Jackson 138 kV and replace the line traps and relays at Maple 138 kV - 6/1/2022 - $7.10M

138) Baseline Upgrade b3068

- Reconductor the Yukon - Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV - 6/1/2022 - $2.50M

139) Baseline Upgrade b3069

- Reconductor the Westraver - Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV - 6/1/2022 - $7.50M

140) Baseline Upgrade b3070

- Reconductor the Yukon - Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV - 6/1/2022 - $10.00M

141) Baseline Upgrade b3071

- Reconductor the Yukon - Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

142) Baseline Upgrade b3072

- Reconductor the Yukon - Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV - 6/1/2022 - $10.00M

143) Baseline Upgrade b3073

- Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor - 6/1/2022 - $2.10M

144) Baseline Upgrade b3074

- Replace Substation conductor on the 345/138 kV transformer at Armstrong substation - 6/1/2022 - $0.10M

145) Baseline Upgrade b3075

- Replace substation conductor and 138 kV circuit breaker on the #1 transformer (500/138 kV) at Cabot substation - 6/1/2022 - $0.30M

146) Baseline Upgrade b3076

- Reconductor the Edgewater - Loyalhanna 138 kV line (0.67 miles) - 6/1/2022 - $2.00M

147) Baseline Upgrade b3077

- Reconductor the Franklin Pike - Wayne 115 kV line (6.78 miles) - 6/1/2022 - $11.40M

148) Baseline Upgrade b3078

- Reconductor 138 kV bus and replace the line trap, relays at Morgan Street. Reconductor 138 kV bus at Venango Junction - 6/1/2022 - $1.00M

149) Baseline Upgrade b3079

- Replace the Wylie Ridge 500/345 kV transformer #7 - 6/1/2022 - $6.37M

150) Baseline Upgrade b3080

- Reconductor 138 kV bus at Seneca - 6/1/2022 - $0.07M

151) Baseline Upgrade b3081

- Replace 138 kV breaker and substation conductor at Krendale - 6/1/2022 - $0.30M

152) Baseline Upgrade b3082

- Construct a 4-breaker 115 kV ring bus at Franklin Pike - 6/1/2022 - $8.00M

153) Baseline Upgrade b3083

- Replace substation conductor at Butler (138 kV) Replace substation conductor and line trap at Karns City (138 kV) - 6/1/2022 - $0.20M

154) Baseline Upgrade b3085

- Reconductor Kammer - George Washington 138 kV line (~0.08 miles). Replace the wave trap at Kammer 138 kV. - 6/1/2022 - $0.50M

155) Baseline Upgrade b3086.2

- Rebuild New Liberty – North Baltimore 34 kV Line Str's 1-11 (0.5 miles), utilizing 795 26/7 ACSR conductor - 6/1/2022 - $1.80M

156) Baseline Upgrade b3086.4

- North Findlay Station: Install a 138 kV 3000 A 63 kA line breaker and low side 34.5 kV 2000 A 40 kA breaker, high side 138 kV circuit switcher on T1 - 6/1/2022 - $1.70M

157) Baseline Upgrade b3087.1

- Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station potentially in/near the new Kentucky Enterprise Industrial Park. . This new station will consist of 4 -138 kV breaker ring bus and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired. - 12/1/2018 - $3.40M

158) Baseline Upgrade b3087.2

- Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Fords Branch station into the existing Beaver Creek – Cedar Creek 138 kV circuit. - 12/1/2018 - $19.90M

159) Baseline Upgrade b3087.3

- Remote end work will be required at Cedar Creek Station. - 12/1/2018 - $0.50M

160) Baseline Upgrade b3087.4

- Install 28.8MVar switching shunt at the new Fords Branch substation - 12/1/2023 - $0.50M

161) Baseline Upgrade b3089

- Rebuild 230kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA. - 6/1/2018 - $112.22M

162) Baseline Upgrade b3090

- Convert the OH portion (approx. 1500 Feet) of 230 kV Lines #248 & #2023 to UG and convert Glebe substation to GIS. - 1/1/2021 - $202.00M

163) Baseline Upgrade b3094

- Move 69 kV 12.0 MVAR capacitor bank from Greenbriar to Bullitt Co 69kV substation - 6/1/2018 - $0.40M

164) Baseline Upgrade b3095

- Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor - 12/1/2022 - $23.90M

165) Baseline Upgrade b3096

- Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA. - 6/1/2019 - $19.00M

166) Baseline Upgrade b3098

- Rebuild 9.8 miles of 115kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA. - 6/1/2019 - $30.90M

167) Baseline Upgrade b3098.1

- Rebuild Balcony Falls Substation - 6/1/2019 - $9.00M

168) Baseline Upgrade b3099

- Install a 138 kV 3000A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer #5 and a 138 kV 3000A 40 kA circuit switcher transformer #7 at Holston station - 6/1/2022 - $0.70M

169) Baseline Upgrade b3100

- Relocate 138 kV circuit breaker W between 138 kV bus #1 extension and bus #2 at Chemical station. Install a new 138 kV circuit breaker between bus #1 and bus #1 extension. - 12/1/2022 - $0.70M

170) Baseline Upgrade b3101

- Rebuild the 1/0 Cu. conductor sections (~1.5 miles) of the Fort Robinson - Moccasin Gap 69 kV line section (~5 miles) utilizing 556 ACSR conductor and upgrade existing relay trip limit (WN/WE: 63 MVA , line limited by remaining conductor sections). - 12/1/2023 - $3.00M

171) Baseline Upgrade b3104

- Perform a sag study on the Polaris - Westerville 138 kV line (~ 3.6 miles) to increase the Summer Emergency rating to 310 MVA. - 6/1/2020 - $0.50M

172) Baseline Upgrade b3108.2

- Install 100 MVAR reactor at Sugarcreek 138 kV substation - 6/1/2019 - $5.00M

173) Baseline Upgrade b3108.3

- Install 100 MVAR reactor at Hutchings 138 kV substation - 6/1/2019 - $5.00M

174) Baseline Upgrade b3114

- Rebuild the 18.6 mile section of 115kV Line #81 which includes 1.7 miles of double circuit Line #81 with 230kV Line #2056 and 1.3 miles of double circuit Line #81 with 230kV Line #239. This segment of Line #81 will be rebuilt to current standards with a minimum rating of 261 MVA. This segment of Line #239 will be rebuilt to current standards with a minimum rating of 1046 MVA. Line #2056 rating will not change. - 6/1/2019 - $27.10M

175) Baseline Upgrade b3115

- Provide new station service to control building from 230 kV bus (served from plant facilities presently). - 9/30/2019 - $1.50M

176) Baseline Upgrade b3116

- Replace existing Mullens 138/46 kV 30 MVA transformer No.4 and associated protective equipment with a new 138/46 kV 90 MVA transformer and associated protective equipment. Install required high side transformer protection by replacing the existing ground switch MOAB with a new 138 kV high side circuit breaker. - 12/1/2022 - $4.00M

177) Baseline Upgrade b3118.3

- Perform 138 kV remote end work at Bellefonte station. - 6/1/2022 - $0.50M

178) Baseline Upgrade b3119.1

- Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station - 6/1/2022 - $38.10M

179) Baseline Upgrade b3119.2

- Install three (3) 69 kV breakers to create the “U” string and add a low side breaker on the Jay transformer 2 - 6/1/2022 - $3.40M

180) Baseline Upgrade b3119.3

- Install two (2) 69 kV breakers at North Portland station to complete the ring and allow for the new line. - 6/1/2022 - $1.90M

181) Baseline Upgrade b3121

- Rebuild Clubhouse-Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA. - 6/1/2019 - $25.50M

182) Baseline Upgrade b3122

- Rebuild Hathaway-Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA. - 6/1/2019 - $13.00M

183) Baseline Upgrade b3123

- At Sammis 345 kV station: Install a new control building in the switchyard, construct a new station access road, install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 6/1/2022 - $8.00M

184) Baseline Upgrade b3124

- Separate metering, station power, and communication at Bruce Mansfield 345 kV station - 12/31/2020 - $0.93M

185) Baseline Upgrade b3125

- At Davis Bessie 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and separate all protection and controls schemes - 5/31/2020 - $1.80M

186) Baseline Upgrade b3126

- At Perry 345 kV station: Install new switchyard power supply to separate from existing generating station power service, separate all communications circuits, and construct a new station access road - 6/1/2021 - $0.60M

187) Baseline Upgrade b3130

- Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), Rebuild/Reconductor two 34.5 kV circuits (total of 5.5 miles) and install a 2nd 115/34.5 kV transformer (Werner) - 6/1/2016 - $223.00M

188) Baseline Upgrade b3130.1

- Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (3.9 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

189) Baseline Upgrade b3130.10

- Install 2nd 115-34.5 kV Transformer at Werner Substation - (replaces B1690) - 6/1/2016 - $0.00M

190) Baseline Upgrade b3130.2

- Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (10.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

191) Baseline Upgrade b3130.3

- Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (10.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

192) Baseline Upgrade b3130.4

- Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (5.6 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

193) Baseline Upgrade b3130.5

- Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5.7 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

194) Baseline Upgrade b3130.6

- Construct a new 34.5 kV circuit from Werner to Clark Street (7.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

195) Baseline Upgrade b3130.7

- Construct a new 34.5 kV circuit from Atlantic to Freneau (13.3 Miles) - (replaces B1690) - 6/1/2016 - $0.00M

196) Baseline Upgrade b3130.8

- Rebuild/Reconductor the Atlantic to Camp Woods Switch Point (3.5 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

197) Baseline Upgrade b3130.9

- Rebuild/Reconductor the Allenhurst to Elberon (2.0 Miles) 34.5 kV circuit - (replaces B1690) - 6/1/2016 - $0.00M

198) Baseline Upgrade b3131

- At East Lima and Haviland.The Haviland – East Lima 138kV line is overloaded for multiple contingencies in winter generator deliverability test and basecase analysis test. 138 kV stations, replace line relays and wavetrap on the East Lima-Haviland 138 kV facility.In addition, replace 500 MCM Cu Risers and Bus conductors at Haviland 138 kV - 12/1/2024 - $1.35M

199) Baseline Upgrade b3131.1

- Rebuild approximately 12.3 miles of remaining Lark conductor on the double circuit line between Haviland and East Lima with 1033 54/7 ACSR conductor. - 12/1/2024 - $25.90M

200) Baseline Upgrade b3133

- Move the existing Botkins 69 kV capacitor from the Sidney-Botkins side of the existing breaker at Botkins to the Botkins-Jackson Center side. This will keep the capacitor in-service for the loss of Sidney-Botkins. This reduces the voltage drop to less than 3% and also resolves the overload on the Blue Jacket Tap-Huntsville 69 kV line. - 6/1/2024 - $0.20M

201) Baseline Upgrade b3134

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview substation (21 miles) and create a line terminal at Belle Haven delivery point (three-breaker ring bus) - 6/1/2019 - $22.00M

202) Baseline Upgrade b3134.1

- Reconfigure the Belle Haven 69 kV bus to three-breaker ring bus and create a line terminal for the new 69 kV circuit to Bayview - 6/1/2019 - $0.00M

203) Baseline Upgrade b3134.2

- Build a new single circuit 69 kV overhead from Kellam sub to new Bayview Substation (21 miles) - 6/1/2019 - $0.00M

204) Baseline Upgrade b3136

- Replace bus conductor at Smith 115 kV substation - 6/1/2024 - $0.24M

205) Baseline Upgrade b3137

- Rebuild 20 miles of the East Towanda - North Meshoppen 115 kV line - 6/1/2024 - $58.60M

206) Baseline Upgrade b3138

- Move 2 MVA load from the Roxborough to Bala substation. Adjust the tap setting on the Master 138/69 kV transformer No.2 - 6/1/2024 - $0.01M

207) Baseline Upgrade b3142

- Rebuild Michigan City-Trail Creek - Bosserman 138 kV (10.7 mi) - 1/1/2023 - $33.26M

208) Baseline Upgrade b3143.1

- Reconductor the Silverside – Darley 69 kV circuit - 6/1/2024 - $1.39M

209) Baseline Upgrade b3143.2

- Reconductor the Darley – Naamans 69 kV circuit - 6/1/2024 - $2.09M

210) Baseline Upgrade b3143.3

- Replace three (3) existing 1200 A disconnect switches with 2000 A disconnect switches and install three (3) new 2000 A disconnect switches at Silverside 69 kV station - 6/1/2024 - $0.48M

211) Baseline Upgrade b3143.4

- Replace two (2) 1200 A disconnect switches with 2000 A disconnect switches, replace existing 954 ACSR and 500 SDCU stranded bus with (2) 954 ACSR stranded bus. Reconfigure four (4) CTs from 1200 A to 2000 A and install two (2) new 2000 A disconnect switches, new (2) 954 ACSR stranded bus at Naamans 69 kV station - 6/1/2024 - $0.60M

212) Baseline Upgrade b3143.5

- Replace four (4) 1200 A disconnect switches with 2000 A disconnect switces. Replace existing 954 ACSR and 1272 MCM AL stranded bus with (2) 954 ACSR stranded bus. Reconfigure eight (8) CTs from 1200 A to 2000 A and install Four (4) new 2000 A (310 MVA SE / 351 MVA WE) disconnect switches, new (2) 954 ACSR (331 MVA SE / 369 MVA WE) stranded bus at Darley 69 kV station - 6/1/2024 - $0.95M

213) Baseline Upgrade b3144

- Upgrade bus conductor and relay panels Jackson Road – Nanty Glo 46 kV SJN line - 6/1/2024 - $1.50M

214) Baseline Upgrade b3144.1

- Upgrade line relaying and substation conductor on the 46 kV Nanty Glo line exit at Jackson Road substation - 6/1/2024 - $0.00M

215) Baseline Upgrade b3144.2

- Upgrade line relaying and substation conductor on the 46 kV Jackson Road line exit at Nanty Glo substation - 6/1/2024 - $0.00M

216) Baseline Upgrade b3149

- Rebuild the 2.3 mile Decatur – South Decatur 69 kV line using 556 ACSR in order to alleviate the overloads. - 6/1/2024 - $9.30M

217) Baseline Upgrade b3150

- Rebuild Ferguson 69/12 kV station in the clear as the 138/12 kV Bear station and connect it to a ~1 mile double circuit 138 kV extension from the Aviation – Ellison Rd 138 kV line to remove the load from the 69 kV line. - 6/1/2024 - $6.40M

218) Baseline Upgrade b3151.1

- Rebuild the ~30 mile Gateway – Wallen 34.5 kV circuit as the ~27 mile Gateway – Wallen 69 kV circuit. - 6/1/2024 - $43.30M

219) Baseline Upgrade b3151.10

- Rebuild the 2.5 mile Columbia – Gateway 69 kV line. - 6/1/2024 - $6.20M

220) Baseline Upgrade b3151.11

- Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers “J” & “K” and 138 kV breaker “D”. - 6/1/2024 - $15.00M

221) Baseline Upgrade b3151.12

- Rebuild the 13 mile Columbia – Richland 69 kV line. - 6/1/2024 - $29.30M

222) Baseline Upgrade b3151.13

- Rebuild the 0.5 mile Whitley – Columbia City No.1 line as 69 kV. - 6/1/2024 - $1.00M

223) Baseline Upgrade b3151.14

- Rebuild the 0.5 mile Whitley – Columbia City No.2 line as 69 kV. - 6/1/2024 - $0.70M

224) Baseline Upgrade b3151.15

- Rebuild the 0.6 mile double circuit section of the Rob Park – South Hicksville / Rob Park – Diebold Road as 69 kV - 6/1/2024 - $1.00M

225) Baseline Upgrade b3151.2

- Retire the ~3 miles Columbia – Whitley 34.5 kV line. - 6/1/2024 - $0.50M

226) Baseline Upgrade b3151.3

- At Gateway station, remove all 34.5 kV equipment and install one (1) 69 kV circuit breaker for the new Whitley line entrance. - 6/1/2024 - $1.00M

227) Baseline Upgrade b3151.4

- Rebuild Whitley as a 69 kV station with two (2) line and one (1) bus tie circuit breakers. - 6/1/2024 - $4.20M

228) Baseline Upgrade b3151.5

- Replace the Union 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

229) Baseline Upgrade b3151.6

- Replace the Eel River 34.5 kV switch with a 69 kV switch structure. - 6/1/2024 - $0.60M

230) Baseline Upgrade b3151.7

- Install a 69 kV Bobay switch at Woodland Station. - 6/1/2024 - $0.60M

231) Baseline Upgrade b3151.8

- Replace Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper will have two (2) line circuit breakers, one (1) bus tie circuit breaker and a 14.4 MVAR cap bank - 6/1/2024 - $8.70M

232) Baseline Upgrade b3151.9

- Remove 34.5 kV circuit breaker "AD" at Wallen station. - 6/1/2024 - $0.30M

233) Baseline Upgrade b3152

- Reconductor the 8.4 mile section of the Leroy Center - Mayfield Q1 line between Leroy Center and Pawnee Tap to achieve a rating of at least 160 MVA / 192 MVA (SN/SE). - 6/1/2022 - $14.10M

234) Baseline Upgrade b3154

- Install one (1) 13.2 MVAR 46 kV capacitor at the Logan substation - 6/1/2024 - $1.70M

235) Baseline Upgrade b3155

- Rebuild approximately 12 miles of Wye Mills - Stevensville line to achieve needed ampacity - 12/1/2023 - $23.60M

236) Baseline Upgrade b3156

- Replace line relaying and fault detector on the Wylie Ridge terminal at Smith 138 kV Substation - 6/1/2022 - $0.85M

237) Baseline Upgrade b3157

- Replace line relaying and fault detector relaying at Messick Rd. and Morgan 138 kV substations; Replace wave trap at Morgan 138 kV substation - 12/1/2024 - $0.23M

238) Baseline Upgrade b3159

- Build a new 138/69 kV substation. Install one (1) 138 kV circuit breaker, one (1) 138/69 kV 130 MVA transformer, three (3) 69 kV circuit breakers. Build a 0.15 mile 138 kV 795 ACSR transmission line between the FE Brim 138/69 kV substation and the newly proposed AMPT substation (three steel poles). Loop the Bowling Green Sub No.5 – Bowling Green Sub No.2 69 kV lines in and out of the newly established substation. Complete the remote end terminal work at BG substations #2 and #5 to accommodate the new substation. - 6/1/2024 - $10.10M

239) Baseline Upgrade b3160.1

- Construct a ~2.4 mile double circuit 138 kV extension using 1033 ACSR to connect Lake Head to the 138 kV network. - 6/1/2024 - $6.00M

240) Baseline Upgrade b3160.2

- Retire the ~2.5 mile 34.5 kV Niles – Simplicity Tap line. - 6/1/2024 - $1.20M

241) Baseline Upgrade b3160.3

- Retire the ~4.6 mile Lakehead 69 kV Tap - 6/1/2024 - $1.40M

242) Baseline Upgrade b3160.4

- Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV MOAB - 6/1/2024 - $4.00M

243) Baseline Upgrade b3160.5

- Rebuild the ~1.2 mile Buchanan South 69 kV Radial Tap using 795 ACSR - 6/1/2024 - $3.00M

244) Baseline Upgrade b3160.6

- Rebuild the ~8.4 mile 69 kV Pletcher – Buchanan Hydro line as the ~9 mile Pletcher – Buchanan South 69 kV line using 795 ACSR. - 6/1/2024 - $20.00M

245) Baseline Upgrade b3160.7

- Install a PoP switch at Buchanan South station with 2 line Moabs. - 6/1/2024 - $0.60M

246) Baseline Upgrade b3161.1

- Install two, 2000 Amp, 115kV line switches. Extend Reymet fence and bus to allow installation of risers to Line #53 (Chesterfield-Kevlar 115 kV). - 6/1/2024 - $3.00M

247) Baseline Upgrade b3162

- Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV (Line #2199) will be cut and connected to the new station. Remington-Mt. Run 115 kV (Line #70) and Mt. Run-Oak Green 115 kV (Line #2) will also be cut and connected to the new station. - 6/1/2024 - $22.00M

248) Baseline Upgrade b3208

- Retire approximately 38 miles of the 44 mile Clifford-Scottsville 46 kV circuit. Build new 138 kV “in and out” to two new Distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls-Riverville (~10 mi.) and Riverville-Gladstone (~5 mi.). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (~4 mi.) - 12/1/2022 - $85.00M

249) Baseline Upgrade b3209

- Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR in order to alleviate the overload and address a deteriorating asset. - 6/1/2022 - $16.60M

250) Baseline Upgrade b3211

- Rebuild the 1.3 mile section of 500 kV Line No.569 (Loudoun - Morrisville) with single-circuit 500 kV structures at the current 500 kV standard. This will increase the rating of the line to 3424 MVA. - 6/1/2019 - $4.50M

251) Baseline Upgrade b3213

- Install 2nd Chickahominy 500/230 kV transformerRelocate the Chickahominy – Elmont 500kV line #557 to terminate in a new bay at Chickahominy substation and relocate the Chesterfield – Lanexa 115kV line #92 to allow for the expansion of the Chickahominy substation • Add three new 500 kV breakers with 50kA interrupting rating and associated equipment - 6/1/2023 - $22.00M

252) Baseline Upgrade b3214

- Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV Line. Upgrade terminal equipment at Yukon and replace line relaying at Mitchell and Charleroi - 6/1/2022 - $24.50M

253) Baseline Upgrade b3214.1

- Reconductor the Yukon – Smithton 138 kV Line. Upgrade terminal equipmet at Yukon and replace line relaying at Michell and Charleroi. - 6/1/2022 - $24.50M

254) Baseline Upgrade b3214.2

- Reconductor the Smithton – Shepler Hill Jct 138 kV Line - 6/1/2022 - $0.00M

255) Baseline Upgrade b3218

- At Oak Mound 138 kV substation, replace the 138 kV bus tie and Waldo Run #2 breakers with 40 kA, 3000 amp units. Install CTs as 2000/5 MR. - - $0.00M

256) Baseline Upgrade b3221

- Replace terminal equipment (bus conductor) on the 230 kV side of the Steel City 500/230 kV transformer #1 - 6/1/2025 - $0.09M

257) Baseline Upgrade b3222

- Install one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Reno 69 kV line and one (1) 7.2 MVAR fixed cap bank on the Lock Haven-Flemington 69 kV line near the Flemington 69/12kV substation. - 6/1/2025 - $1.90M

258) Baseline Upgrade b3223.1

- Install a 2nd 230kV circuit with a minimum summer emergency rating of 1047 MVA between Lanexa and Northern Neck Substations. The 2nd circuit will utilize the vacant arms on the double-circuit structures that are being installed on the Line #224 (Lanexa-Northern Neck) End-of-Life rebuild project (b3089). - 6/1/2023 - $14.00M

259) Baseline Upgrade b3223.2

- Expand the Northern Neck terminal from a 230kV, 4-breaker ring bus to a 6-breaker ring bus.

- 6/1/2023 - $5.00M

260) Baseline Upgrade b3223.3

- Expand the Lanexa terminal from a 6-breaker ring bus to a breaker-and-a-half arrangement. - 6/1/2023 - $4.00M

261) Baseline Upgrade b3224

- Replace a disconnect switch and reconductor a short span of Mt. Pleasant - Middletown Tap line - 6/1/2025 - $0.43M

262) Baseline Upgrade b3226

- Add 10 MVAR 69 kV capacitor bank at Swainton substation - 6/1/2025 - $2.90M

263) Baseline Upgrade b3227

- Rebuild the Corson-Court 69 kV line to achieve ratings equivalent to 795 ACSR conductor or better - 6/1/2025 - $13.20M

264) Baseline Upgrade b3228

- Replace two relays at Center Substation to increase ratings on the 110552 circuit - 6/1/2025 - $0.03M

265) Baseline Upgrade b3230

- At Enon Substation install a second 138 kV, 28.8 MVAR nameplate, capacitor and the associated 138 kV capacitor switcher. - 6/1/2025 - $1.84M

266) Baseline Upgrade b3231

- Replace the existing No. 2 cap bank breaker at Huntingdon substation with a new breaker with higher interrupting capability. - 6/1/2025 - $0.80M

267) Baseline Upgrade b3232

- Replace the existing Williamsburg, ALH (Hollidaysburg) and bus section breaker at the Altoona substation with a new breaker with higher interrupting capability. - 6/1/2025 - $1.70M

268) Baseline Upgrade b3233

- Install one 34 MVAR 115 kV shunt reactor and breaker. Install one 115 kV circuit breaker to expand the substation to a 4 breaker ring bus. - 6/1/2025 - $4.90M

269) Baseline Upgrade b3234

- Extend both the east and west 138 kV buses at Pine substation, and install one 138 kV breaker, associated disconnect switches, and one 100 MVAR reactor. - 6/1/2025 - $3.80M

270) Baseline Upgrade b3235

- Extend 138 kV bus work to the west of Tangy substation for the addition of the 100 MVAR reactor bay and one 138 kV 40 kA circuit breaker. - 6/1/2025 - $3.70M

271) Baseline Upgrade b3236

- Extend the 138 kV Bus by adding two new breakers and associated equipment and install a 75 MVAR Reactor - 6/1/2025 - $4.50M

272) Baseline Upgrade b3237

- Install two 46 kV 6.12 MVAR capacitors effective at Mt Union. - 6/1/2025 - $4.00M

273) Baseline Upgrade b3238

- Replace (7) overdutied 34.5 kV breakers with 50 kA rated equipment at the Whippany substation. - 6/1/2025 - $5.10M

274) Baseline Upgrade b3239

- Replace (14) overdutied 34.5 kV breakers with 63 kA rated equipment. - 6/1/2025 - $8.50M

275) Baseline Upgrade b3240

- Upgrade Cherry Run and Morgan terminals to make the Transmission Line the limiting component.

  Morgan: Wave Trap

  Cherry Run: Substation conductor, relays, CT - 6/1/2024 - $1.10M

276) Baseline Upgrade b3241

- Install 138 kV, 36 MVAR capacitor and a 5 uF reactor protected by a 138 kV capacitor switcher. Install a breaker on the 138 kV Junction terminal. Install a 138 kV 3.5 uF reactor on the existing Hardy 138 kV capacitor. - 6/1/2025 - $2.85M

277) Baseline Upgrade b3242

- Reconfigure Stonewall 138 kV substation from its current configuration to a six-breaker breaker-and-a-half layout and add two 36 MVAR capacitors with capacitor switchers. - 6/1/2025 - $13.30M

278) Baseline Upgrade b3243

- Replace risers at Bass 34.5kV station - 6/1/2025 - $0.10M

279) Baseline Upgrade b3244

- Rebuild approximately 9 miles of the Rob Park - Harlan 69 kV line - 6/1/2025 - $20.90M

280) Baseline Upgrade b3245

- Construct a new breaker-and-a-half substation near Tiffany substation. All transmission assets and lines will be relocated to the new substation. The two distribution transformers will be fed via two dedication 115 kV feeds to the existing Tiffany substation. - 6/1/2025 - $23.20M

281) Baseline Upgrade b3246.1

- Convert 115 kV Line #172 Liberty-Lomar and 115 kV Line #197 Cannon Branch-Lomar to 230 kV to provide a new 230 kV source between Cannon Branch and Liberty. The majority of 115 kV Line #172 Liberty-Lomar and Line #197 Cannon Branch-Lomar is adequate for 230 kV operation. Lines to have a summer rating of 1047 MVA/1047 MVA (SN/SE) - 6/1/2023 - $8.00M

282) Baseline Upgrade b3246.2

- Perform substation work for the 115 kV to 230 kV Line conversion at Liberty, Wellington, Godwin, Pioneer, Sandlot and Cannon Branch. - 6/1/2023 - $20.00M

283) Baseline Upgrade b3246.3

- Extend 230kV Line #2011 Cannon Branch – Clifton to Winters Branch by removing the existing Line #2011 termination at Cannon Branch and extending the line to Brickyard creating 230kV Line #2011 Brickyard-Clifton. Extend a new 230kV line between Brickyard and Winters Branch with a summer rating of 1572MVA/1572MVA (SN/SE) - 6/1/2023 - $10.29M

284) Baseline Upgrade b3246.4

- Perform substation work at Cannon Branch, Brickyard and Winters Branch for the 230kV Line #2011 extension. - 6/1/2023 - $1.41M

285) Baseline Upgrade b3246.5

- Replace the Gainesville 230kV 40kA breaker “216192” with a 50kA breaker. - 6/1/2023 - $0.50M

286) Baseline Upgrade b3247

- Replace 13 towers with galvanized steel towers on Doubs - Goose Creek 500 kV. Reconductor 3 mile section with 3-1351.5 ACSR 45/7. Upgrade line terminal equipment at Goose Creek substation to support the 500 kV line rebuild. - 6/1/2025 - $7.60M

287) Baseline Upgrade b3248

- Install a low side 69 kV circuit breaker at Albion 138/69 kV transformer 1 - 6/1/2025 - $0.40M

288) Baseline Upgrade b3249

- Rebuild the Chatfield-Melmore 138kV line (~ 10 miles) to 1033 ACSR conductor. - 6/1/2025 - $27.20M

289) Baseline Upgrade b3253

- Install a 3000A 40 kA 138 kV breaker on high side of 138/69 kV transformer #5 at Millbrook Park station. The transformer and associated bus protection will be upgraded accordingly. - 6/1/2025 - $0.63M

290) Baseline Upgrade b3255

- Upgrade 795 AAC risers at Sand Hill 138 kV station towards Cricket Switch with 1272 AAC - 6/1/2025 - $0.04M

291) Baseline Upgrade b3257

- Replace two spans of 336.4 26/7 ACSR on Twin Branch-AM General #2 34.5 kV circuit - 6/1/2025 - $0.14M

292) Baseline Upgrade b3258

- Install a 3000A 63 kA 138 kV breaker on high side of 138/69 kV transformer #2 at Wagenhals station. The transformer and associated bus protection will be upgraded accordingly. - 6/1/2025 - $1.10M

293) Baseline Upgrade b3259

- At West Millersburg station, replace the 138 kV MOAB on the West Millersburg - Wooster 138 kV line with a 3000A 40 kA breaker. - 6/1/2025 - $0.68M

294) Baseline Upgrade b3262

- Install a second 115kV 33.67MVar cap bank at Harrisonburg substation along with a 115kV breaker. - 12/1/2025 - $1.25M

295) Baseline Upgrade b3264

- Install 115kV breaker at Stuarts Draft station and sectionalize 115kV Line#117 into two 115kV lines. - 6/1/2025 - $5.00M

296) Baseline Upgrade b3265

- Implement slow circulation on existing underground 138 kV high pressure fluid filled (HPFF) cable between Arsenal and Riazzi substations. - 6/1/2025 - $2.40M

297) Baseline Upgrade b3267

- Rebuild the 4/0 ACSR Norwood-Shopville 69 kV line section using 556 ACSR/TW. - 12/1/2021 - $3.75M

298) Baseline Upgrade b3268

- Build a switching station at the junction of 115kV line #39 and 115kV line #91 with a 115kV capacitor bank. The switching station will built with 230kV structures but will operate at 115kV. - 12/1/2025 - $3.00M

299) Baseline Upgrade b3269

- At West New Philadelphia station, add a high side 138 kV breaker on the 138/69 kV transformer #2 along with a 138 kV breaker on the line towards Newcomerstown. - 6/1/2025 - $2.02M

300) Baseline Upgrade b3270

- Install 1.7 miles of 795 ASCR 138kV conductor along the other side of Dragoon Tap 138 kV line, which is currently double circuit tower with one position open. Additionally, install a 2nd 138/34.5 kV transformer at Dragoon, install a high side circuit switcher on the current transformer at Dragoon Station, and install 2-138 kV line breakers on the Dragoon-Jackson 138 kV and Dragoon-Twin Branch 138 kV lines. - 6/1/2025 - $4.89M

301) Baseline Upgrade b3270.1

- Replace Dragoon 34.5 kV Breakers "B", "C" and "D" with 40 kA breakers. - 6/1/2025 - $2.00M

302) Baseline Upgrade b3271

- Install a 138 kV circuit breaker at Fremont station on line towards Fremont Center and install a 9.6 MVAR 69 kV capacitor bank at Bloom Road station. - 6/1/2025 - $1.76M

303) Baseline Upgrade b3272

- Install two 138 kV circuit switchers on the high side of 138/34.5 kV transformers #1 & #2 at Rockhill station. - 6/1/2025 - $1.47M

304) Baseline Upgrade b3273.1

- Rebuild and convert the existing 17.6 miles East Leipsic-New Liberty 34.5 kV circuit to 138 kV using 795 ACSR - 6/1/2025 - $31.35M

305) Baseline Upgrade b3273.2

- Convert the existing 34.5 kV equipment to 138 kV and expanded the existing McComb station to the north and east to allow for new equipment to be installed. Install two new 138 kV box bays to allow for line positions and two new 138/12 kV transformers. - 6/1/2025 - $0.87M

306) Baseline Upgrade b3273.3

- Expand the existing East Leipsic 138 kV station to the north to allow for another 138 kV line exit to be installed. The new line exit will involve installing a new 138 kV circuit breaker, disconnect switches and new dead end structure along with extending existing 138 kV bus work. - 6/1/2025 - $1.30M

307) Baseline Upgrade b3273.4

- Add one 138 kV circuit breaker and disconnect switches in order to add an additional line position at New Liberty 138 kV station. Install line relaying potential devices and retire the 34.5 kV breaker F. - 6/1/2025 - $0.90M

308) Baseline Upgrade b3274

- Rebuild approximately 8.9 miles of 69 kV line between Newcomerstown and Salt Fork Switch with 556 ACSR conductor. - 6/1/2025 - $15.89M

309) Baseline Upgrade b3275.1

- Rebuild Kammer Station-Cresaps Switch 69 kV, approximately 0.5 miles. - 6/1/2025 - $0.93M

310) Baseline Upgrade b3275.2

- Rebuild Cresaps Switch-McElroy Station 69 kV, approximately 0.67 miles. - 6/1/2025 - $1.25M

311) Baseline Upgrade b3275.3

- Replace a single span of 4/0 ACSR from Moundsville-Natrium str 93L to Carbon Tap switch 69kV located between Colombia Carbon and Conner Run stations. Remainder of line is 336 ACSR. - 6/1/2025 - $0.01M

312) Baseline Upgrade b3275.4

- Rebuild from Colombia Carbon to Columbia Carbon Tap str 93N 69 kV, approximately 0.72 miles. The remainder of the line between Colombia Carbon Tap structure 93N and Natrium station is 336 ACSR and will remain. - 6/1/2025 - $1.08M

313) Baseline Upgrade b3275.5

- Replace the Cresaps 69 kV 3-Way Phase-Over-Phase Switch and structure with a new 1200 A 3-Way Switch and Steel Pole. - 6/1/2025 - $0.71M

314) Baseline Upgrade b3275.6

- Replace 477 MCM Alum bus and risers at McElroy 69 kV station. - 6/1/2025 - $0.33M

315) Baseline Upgrade b3275.7

- Replace Natrium 138 kV bus existing between CB-BT1 and along the 138 kV Main Bus # 1 dropping to CBH1 from the 500MCM conductors to a 1272 KCM AAC conductor. Replace the dead end clamp and strain insulators. - 6/1/2025 - $0.29M

316) Baseline Upgrade b3276.1

- Rebuild the 2/0 Copper section of the Lancaster-South Lancaster 69 kV line, approximately 2.9 miles of the 3.2 mile total length with 556 ACSR conductor. The remaining section has 336 ACSR conductor. - 6/1/2025 - $5.37M

317) Baseline Upgrade b3276.2

- Rebuild the 1/0 Copper section of the line between Lancaster Junction and Ralston station 69 kV, approximately 2.3 miles of the 3.1 mile total length. - 6/1/2025 - $4.58M

318) Baseline Upgrade b3276.3

- Rebuild the 2/0 Copper portion of the line between East Lancaster Tap and Lancaster 69 kV, approximately 0.81 miles. - 6/1/2025 - $1.20M

319) Baseline Upgrade b3277

- Replace the existing East Akron 138 kV breaker B-22 with 3000A continuous, 40 KA momentary current interrupting rating circuit breaker. - 6/1/2021 - $0.55M

320) Baseline Upgrade b3278.1

- Saltville Station: Replace H.S. MOAB Switches on the high side of the 138/69/34.5 kV T1 with a H.S. Circuit Switcher. - 12/1/2025 - $0.72M

321) Baseline Upgrade b3278.2

- Meadowview Station: Replace existing 138/69/34.5 kV transformer T2 with a new 130 MVA 138/69/13 kV transformer. - 12/1/2025 - $3.14M

322) Baseline Upgrade b3278.3

- Saltville Station: Install two 138 kV breakers and bus diff protection - 12/1/2025 - $0.36M

323) Baseline Upgrade b3279

- Install a new 138 kV, 21.6 MVAR cap bank and circuit switcher at Apple Grove Station. - 6/1/2025 - $1.00M

324) Baseline Upgrade b3280

- Rebuild the existing Cabin Creek - Kelly Creek 46 kV line (to structure 366-44), approximately 4.4 miles. This section is double circuit with the existing Cabin Creek - London 46 kV line so a double circuit rebuild would be required. - 6/1/2025 - $17.90M

325) Baseline Upgrade b3281

- Install 138 kV circuit switcher on the 138/69 kV transformer #1 and 138/34.5 kV transformer #2 at Dewey. Install 138 kV 2000 A 40 kA breaker on Stanville line at Dewey 138 kV substation. - 12/1/2025 - $1.40M

326) Baseline Upgrade b3282.1

- Install a second 138 kV circuit utilizing 795 ACSR conductor on the open position of the existing double circuit towers from East Huntington-North Proctorville. Remove the existing 34.5 kV line from East Huntington-North Chesapeake and rebuild this section to 138 kV served from a new PoP switch off the new East Huntington-North Proctorville 138 kV #2 line. - 6/1/2025 - $7.10M

327) Baseline Upgrade b3282.2

- Install a 138 kV 40 kA circuit breaker at North Proctorville. - 6/1/2025 - $1.40M

328) Baseline Upgrade b3282.3

- Install a 138 kV 40 kA circuit breaker at East Huntington. - 6/1/2025 - $1.10M

329) Baseline Upgrade b3282.4

- Convert the existing 34/12 kV North Chesapeake to a 138/12 kV station. - 6/1/2025 - $0.80M

330) Baseline Upgrade b3283

- Replace the existing Inez 138/69 kV 50 MVA autotransformer with a 138/69 kV 90 MVA autotransformer. - 12/1/2025 - $2.96M

331) Baseline Upgrade b3284

- Rebuild ~5.44 miles of 69 kV line from Lock Lane to Point Pleasant. - 6/1/2025 - $13.50M

332) Baseline Upgrade b3285

- Replace the Meigs 69 kV 4/0 Cu station riser towards Gavin and rebuild the section of the Meigs – Hemlock 69 kV circuit from Meigs to approximately structure #40 (~4 miles) replacing the line conductor 4/0 ACSR with the line conductor size 556.5 ACSR. - 6/1/2025 - $12.14M

333) Baseline Upgrade b3287

- Upgrade 69 kV risers at Moundsville station towards George Washington. - 6/1/2025 - $0.05M

334) Baseline Upgrade b3288.1

- Construct ~ 2.75 mi Orinoco - Stone 69 kV transmission line in the clear between Orinoco station and Stone station. - 12/1/2025 - $9.23M

335) Baseline Upgrade b3288.2

- Construct ~ 3.25 mi Orinoco – New Camp 69 kV transmission line in the clear between Orinoco station and New Camp station. - 12/1/2025 - $9.95M

336) Baseline Upgrade b3288.3

- At Stone substation, circuit breaker A to remain in place and be utilized as T1 low side breaker, circuit breaker B to remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69 kV line breaker. Add new 69 kV circuit breaker E for Coleman Line exit. - 12/1/2025 - $0.66M

337) Baseline Upgrade b3288.4

- Reconfigure the New Camp 69 kV tap which includes access road improvements/installation, temporary wire and permanent wire work along with dead end structures installation. - 12/1/2025 - $0.45M

338) Baseline Upgrade b3288.5

- At New Camp substation, rebuild the 69 kV bus, add 69 kV MOAB W and replace the 69 kV ground switch Z1 with a 69 kV circuit switcher on the New Camp transformer. - 12/1/2025 - $1.18M

339) Baseline Upgrade b3289.1

- Roanoke Station: Install high-side circuit switcher on 138/69/12 kV T5 - 6/1/2025 - $1.10M

340) Baseline Upgrade b3289.2

- Huntington Court Station: Install high-side circuit switcher on 138/69/34.5 kV T1 - 6/1/2025 - $1.42M

341) Baseline Upgrade b3290.1

- Build 9.4 miles of single circuit 69 kV line from Roselms to near East Ottoville 69 kV Switch. - 6/1/2025 - $13.70M

342) Baseline Upgrade b3290.2

- Rebuild 7.5 miles of double circuit 69kV line between East Ottoville Switch and Kalida Station (combining with the new Roselms to Kalida 69 kV circuit). - 6/1/2025 - $23.60M

343) Baseline Upgrade b3290.3

- At Roselms Switch, install a new three way 69kV, 1200 A phase-over-phase switch, with sectionalizing capability. - 6/1/2025 - $0.60M

344) Baseline Upgrade b3290.4

- At Kalida 69 kV station, terminate the new line from Roselms Switch. Move the CS XT2 from high side of T2 to the high side of T1. Remove existing T2 transformer. - 6/1/2025 - $1.00M

345) Baseline Upgrade b3291

- Replace the Russ St. 34.5 kV Switch - 6/1/2025 - $1.50M

346) Baseline Upgrade b3292

- Replace existing 69 kV capacitor bank at Stuart Station with a 17.2 MVAr capacitor bank - 12/1/2025 - $0.00M

347) Baseline Upgrade b3293

- Replace 2/0 Cu entrance span conductor on the South Upper Sandusky 69 kV line and 4/0 Cu Risers/Bus conductors on the Forest line at Upper Sandusky 69 kV station. - 6/1/2025 - $0.54M

348) Baseline Upgrade b3294

- Replace existing 69 kV disconnect switches for circuit breaker "C" at Walnut Avenue station - 6/1/2025 - $0.00M

349) Baseline Upgrade b3295

- Grundy 34.5 kV: Install a 34.5 kV 9.6 MVAR cap bank - 6/1/2025 - $0.80M

350) Baseline Upgrade b3296

- Rebuild the overloaded portion of the Concord-Whitaker 34.5 kV line (1.13 miles). Rebuild is double circuit and will utilize 795 ACSR conductor. - 6/1/2025 - $2.80M

351) Baseline Upgrade b3297.1

- Rebuild 4.23 miles of 69 kV line between Sawmill and Lazelle station, using 795 ACSR 26/7 conductor. - 6/1/2025 - $12.00M

352) Baseline Upgrade b3297.2

- Rebuild 1.94 miles of 69 kV line between Westerville and Genoa stations, using 795 ACSR 26/7 conductor. - 6/1/2025 - $5.90M

353) Baseline Upgrade b3297.3

- Replace risers and switchers at Lazelle, Westerville, and Genoa 69 kV stations. Upgrade associated relaying accordingly. - 6/1/2025 - $1.90M

354) Baseline Upgrade b3298

- Rebuild 0.8 miles of double circuit 69 kV line between South Toronto and West Toronto. Replace 219 kcmil ACSR with 556 ACSR. - 6/1/2025 - $2.83M

355) Baseline Upgrade b3298.1

- Replace the 69 kV breaker D at South Toronto station with 40 kA breaker. - 6/1/2025 - $0.70M

356) Baseline Upgrade b3299

- Rebuild 0.2 mile of the West End Fostoria - Lumberjack Switch 69 kV line with 556 ACSR (Dove) conductors. Replace jumpers on West End Fostoria line at Lumberjack Switch. - 6/1/2025 - $0.47M

357) Baseline Upgrade b3300

- Reconductor 230kV Line #2172 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.32M

358) Baseline Upgrade b3301

- Reconductor 230kV Line #2210 from Brambleton to Evergreen Mills along with upgrading the line leads at Brambleton to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $2.26M

359) Baseline Upgrade b3302

- Reconductor 230kV Line #2213 from Cabin Run to Yardley Ridge along with upgrading the line leads at Yardley to achieve a summer emergency rating of 1574 MVA. - 6/1/2025 - $1.75M

360) Baseline Upgrade b3303.1

- Extend a new single circuit 230KV line (#9250) from Farmwell Substation to Nimbus Substation. - 6/1/2025 - $5.65M

361) Baseline Upgrade b3303.2

- Remove Beaumeade 230kV Line #2152 line switch. - 6/1/2025 - $0.05M

362) Baseline Upgrade b3304

- Midlothian Area 300 MW Load Drop Relief Area Improvements - 6/1/2025 - $6.22M

363) Baseline Upgrade b3304.1

- Cut 230kV Line #2066 at Trabue junction - 6/1/2025 - $0.00M

364) Baseline Upgrade b3304.2

- Reconductor idle 230kV Line #242 (radial from Midlothian to Trabue junction) to allow a minimum summer rating of 1047 MVA and connect to the section of 230kV Line #2066 between Trabue junction and Winterpock; re-number 230kV Line #242 structures to #2066; -

6/1/2025 - $0.00M

365) Baseline Upgrade b3304.3

- Use the section of idle 115kV Line #153, between Midlothian and Trabue junction to connect to the section of (former) 230kV Line #2066 between Trabue junction and Trabue to create new Midlothian-Trabue lines with new line numbers #2218 and #2219 - 6/1/2025 - $0.00M

366) Baseline Upgrade b3304.4

- Create new line terminations at Midlothian for the new Midlothian-Trabue lines. - 6/1/2025 - $0.00M

367) Baseline Upgrade b3305

- Replace Pumphrey 230/115kV transformer - 6/1/2025 - $4.69M

368) Baseline Upgrade b3306

- Install a second 125 MVAR 345 kV shunt reactor and associated equipment at Pierce Brook Substation. Install a 345 kV breaker on the high side of the #1 345/230 kV transformer - 6/1/2025 - $8.08M

369) Baseline Upgrade b3307

- Rebuild Fleming station in the clear; Replace 138/69kV Fleming Transformer #1 with 138/69 kV 130 MVA transformer with high side 138 kV CB; Install a 5 breaker 69 kV ring bus on the low side of the transformer, replace 69 kV circuit switcher AA, replace 69/12kV transformer #3 with 69/12 kV 30 MVA transformer, replace 12 kV CB A and D. Retire existing Fleming substation. - 12/1/2025 - $21.10M

370) Baseline Upgrade b3308

- Reconductor and rebuild 1 span of T-line on the Fort Steuben-Sunset Blvd 69 kV branch with 556 ACSR. - 6/1/2025 - $0.73M

371) Baseline Upgrade b3309

- Rebuild 1.75 miles of the Greenlawn - East Tiffin line section of the Carrothers - Greenlawn 69 kV circuit containing 133 ACSR conductor with 556 ACSR conductor. Upgrade relaying as required. - 6/1/2025 - $3.45M

372) Baseline Upgrade b3310.1

- Rebuild 10.5 miles of the Howard-Willard 69 kV line utilizing 556 ACSR conductor. - 6/1/2025 - $19.00M

373) Baseline Upgrade b3310.2

- Upgrade relaying at Howard 69 kV station. - 6/1/2025 - $0.23M

374) Baseline Upgrade b3310.3

- Upgrade relaying at Willard 69 kV station. - 6/1/2025 - $0.23M

375) Baseline Upgrade b3311

- Install a 120.75 kV 79.4 MVAR capacitor bank at Yorkana 115 kV - 5/31/2022 - $2.20M

376) Baseline Upgrade b3312

- Rebuild approximately 4.0 miles of existing 69 kV line between West Mount Vernon and Mount Vernon stations. Replace the existing 138/69 kV transformer at West Mount Vernon with a larger 90 MVA unit along with existing 69 kV breaker 'C'. - 6/1/2025 - $12.93M

377) Baseline Upgrade b3313

- Add 40 kA circuit breakers on the low and high side of East Lima 138/69 kV Transformer - 6/1/2025 - $1.20M

378) Baseline Upgrade b3314.1

- Install a new 138/69 kV 130 MVA transformer and associated protection at Elliot station. - 6/1/2025 - $3.00M

379) Baseline Upgrade b3314.2

- Perform work at Strouds Run station to retire 138/69/13 kV 33.6 MVA transformer #1 and install a dedicated 138/13 KV distribution transformer. - 6/1/2025 - $0.00M

380) Baseline Upgrade b3315

- Upgrade Relaying on Mark Center-South Hicksville 69 kV line and replace Mark Center cap bank with a 7.7 MVAR unit. - 6/1/2025 - $1.25M

381) Baseline Upgrade b3316

- Greene Substation - replace 138 kV 40 kA breaker GJ-138C with a 63 kA breaker - 6/1/2025 - $0.28M

382) Baseline Upgrade b3319

- Add forced cooling to increase the normal rating of the Brunot Island-Carson (302) 345 kV High Pressure Fluid Filled (HPFF) underground cable circuit - 6/1/2022 - $22.00M

383) Baseline Upgrade b3321

- Rebuild Cranes Corner-Stafford 230 kV line - 6/1/2022 - $20.20M

384) Baseline Upgrade b3324

- Replace the bus section at Olive - 6/1/2022 - $0.10M

385) Baseline Upgrade b3325

- Reconductor the Charleroi-Union 138 kV line and upgrade terminal equipment at Charleroi - 6/1/2022 - $11.00M

386) Baseline Upgrade b3326

- Rebuild the 13707 Vienna-Nelson 138 kV line - 6/1/2022 - $43.50M

387) Baseline Upgrade b3327

- Upgrade the disconnect switch (6784-L1) at Kent - 6/1/2022 - $0.25M

388) Baseline Upgrade b3328

- Upgrade the disconnect switch (13710-L1) and CT at Vienna - 6/1/2022 - $0.25M

389) Baseline Upgrade b3329

- Rerate the 13773 Farmview-Milford 138 kV line - 6/1/2022 - $0.20M

390) Baseline Upgrade b3330

- Rerate the 13774 Farmview-S. Harrington 138 kV line - 6/1/2022 - $0.25M

391) Baseline Upgrade b3331

- Upgrade bus conductor and relay at Seaford 138 kV - 6/1/2022 - $0.50M

392) Baseline Upgrade b3332

- Rerate the 23076 Steel-Milford 230 kV line - 6/1/2022 - $0.60M

393) Baseline Upgrade b3333.1

- Rebuild Skeggs Branch substation in the clear as Coronado substation. Establish New 138 kV and 69 kV Buses. Install 138/69 kV 130 MVA transformer, 138 kV circuit switcher and 69 kV breaker. Retire Existing Skeggs Branch substation. - 6/1/2023 - $6.32M

394) Baseline Upgrade b3333.10

- At Whetstone Branch substation, Replace 69KV 600A 2 Way POP Switch with 69KV 1200A 2 Way POP Switch. Remove 69KV to Skeggs Branch (Switch "22" POP). - 6/1/2023 - $0.57M

395) Baseline Upgrade b3333.11

- At Garden Creek substation, remove 69 kV Richlands (via Coal Creek) line (Circuit Breaker F and disconnect switches) and update relay settings. - 6/1/2023 - $0.14M

396) Baseline Upgrade b3333.12

- Remote end work at Clinch River substation - 6/1/2023 - $0.08M

397) Baseline Upgrade b3333.13

- Remote end work at Clinchfield substation. - 6/1/2023 - $0.08M

398) Baseline Upgrade b3333.2

- New ~1.2 mi 138kV extension to new Skeggs Branch substation location. - 6/1/2023 - $4.62M

399) Baseline Upgrade b3333.3

- Install 46.1 MVAR Cap bank at Whitewood substation along with a 138 kV breaker. - 6/1/2023 - $1.05M

400) Baseline Upgrade b3333.4

- Rebuild ~9 mi 69kV line from new Skeggs branch station to Coal Creek 69kV line. 6-wire the short double circuit section between Whetstone Branch and Str. 340-28 to convert the line to single circuit. Retire Garden Creek to Whetstone Branch 69kV line section. - 6/1/2023 - $26.25M

401) Baseline Upgrade b3333.5

- Retire Knox Creek SS. - 6/1/2023 - $0.06M

402) Baseline Upgrade b3333.6

- Retire Horn Mountain SS. This will be served directly from 69kV bus at New Skeggs branch Substation. - 6/1/2023 - $0.05M

403) Baseline Upgrade b3333.7

- At Clell SS, replace two 600A POP Switches and Poles with single 2 Way 1200A POP Switch and Pole. - 6/1/2023 - $0.34M

404) Baseline Upgrade b3333.8

- At Permac, replace 600A Switch and structure with 2 Way 1200A POP Pole Switch and pole. - 6/1/2023 - $0.31M

405) Baseline Upgrade b3333.9

- At Marvin SS, replace 600 A Switch and structure with 2 Way 1200 A POP Pole Switch and pole. - 6/1/2023 - $0.31M

406) Baseline Upgrade b3334

- Rebuild the section of Miami Fort-Hebron Tab 138 kV - 6/1/2022 - $44.30M

407) Baseline Upgrade b3335

- Reconductor a 0.76 mile portion of the Croydon-Burlington 230 kV line - 6/1/2022 - $0.79M

408) Baseline Upgrade b3337

- Replace the one (1) Hyatt 138 kV breaker “AB1(101N)” with 3000 A, 63 kA interrupting breaker. - 6/1/2026 - $0.48M

409) Baseline Upgrade b3338

- Replace the two (2) Kenny 138 kV breakers, “102” (SC-3) and “106” (SC-4), each with a 3000 A, 63 kA interrupting breaker. - 6/1/2026 - $0.76M

410) Baseline Upgrade b3339

- Replace the one (1) Canal 138 kV breaker “3” with 3000 A, 63 kA breaker. - 6/1/2026 - $0.48M

411) Baseline Upgrade b3341.1

- Marysville Substation: Install two 69 kV 16.6 MVAR cap banks; Install five 69 kV circuit breakers; Upgrade station relaying; Replace 600 A wave trap on the Marysville-Kings Creek 69 kV (6660) circuit - 6/1/2026 - $2.43M

412) Baseline Upgrade b3341.2

- Darby Substation: Upgrade remote end relaying at Darby 69 kV substation - 6/1/2026 - $0.25M

413) Baseline Upgrade b3341.3

- Kings Creek: Upgrade remote end relaying at Kings Creek 69 kV substation - 6/1/2026 - $0.25M

414) Baseline Upgrade b3342

- Replace the 2156 ACSR & 2874 ACSR bus and risers with 2-bundled 2156 ACSR at Muskingum River 345 kV station to address loading issues on Muskingum-Waterford 345 kV line. - 6/1/2026 - $0.53M

415) Baseline Upgrade b3343

- Rebuild approximately 0.3 miles of overloaded 69 kV line between Albion-Philips Switch and Philips Switch-Brimfield Switch with 556 ACSR conductor. - 6/1/2026 - $0.61M

416) Baseline Upgrade b3344.1

- Install two (2) 138 kV circuit breakers in the M and N strings in the breaker-and-a half configuration in West Kingsport station 138 kV yard to allow the Clinch River-Moreland Dr. 138 kV to cut in the West Kingsport station - 11/1/2026 - $1.85M

417) Baseline Upgrade b3344.2

- Upgrade remote end relaying at Riverport 138 kV station due to the line cut in at West Kingsport station - 11/1/2026 - $0.25M

418) Baseline Upgrade b3345.1

- Rebuild ~4.2 miles of overloaded sections of the 69 kV line between Salt Fork Switch and Leatherwood Switch with 556 ACSR. - 6/1/2026 - $9.06M

419) Baseline Upgrade b3345.2

- Update relay settings at Broom Road station. - 6/1/2026 - $0.04M

420) Baseline Upgrade b3346.1

- Rebuild approximately 3.5 miles of overloaded 69 kV line between North Delphos-East Delphos-Elida Road switch. This includes approximately 1.1 miles of double circuit line that makes up a portion of the North Delphos-South Delphos 69 kV line and the North Delphos-East Delphos 69 kV line. Approximately 2.4 miles of single circuit line will also be rebuilt between the double circuit portion to East Delphos station and from East Delphos to Elida

Road Switch. - 6/1/2026 - $8.43M

421) Baseline Upgrade b3346.2

- Replace the line entrance spans at South Delphos to eliminate the overloaded 4/0 Copper and 4/0 ACSR conductor. - 6/1/2026 - $0.44M

422) Baseline Upgrade b3347.1

- Rebuild approximately 20 miles of line between Bancroft and Milton stations with 556 ACSR conductor - 11/1/2026 - $56.55M

423) Baseline Upgrade b3347.2

- Replace the jumpers around Hurrican switch with 556 ACSR - 11/1/2026 - $0.01M

424) Baseline Upgrade b3347.3

- Replace the jumpers around Teays switch with 556 ACSR - 11/1/2026 - $0.01M

425) Baseline Upgrade b3347.4

- Winfield Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.05M

426) Baseline Upgrade b3347.5

- Bancroft Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.03M

427) Baseline Upgrade b3347.6

- Milton Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild. - 11/1/2026 - $0.03M

428) Baseline Upgrade b3347.7

- Putnam Village Station Relay Settings: Update relay settings to coordinate with remote ends on line rebuild - 11/1/2026 - $0.05M

429) Baseline Upgrade b3348.1

- Construct a 138 kV single bus station (Tin Branch) consisting of a 138 kV box bay with a distribution transformer and 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Sprigg stations), and distribution will have one 12 kV feed. Install two 138 kV circuit breakers on the line exits. Install 138 kV circuit switcher for the new transformer. - 11/1/2026 - $5.58M

430) Baseline Upgrade b3348.2

- Construct a new 138/46/12 kV Argyle station to replace Dehue station. Install a 138 kV ring bus using a breaker-and-a-half configuration, with an autotransformer with a 46 kV feed and a distribution transformer with a 12 kV distribution bay. Two 138 kV lines will feed this station (from Logan and Wyoming stations). There will also be a 46 kV feed from this station to Becco station. Distribution will have two 12 kV feeds. Retire Dehue station in its entirety. - 11/1/2026 - $10.00M

431) Baseline Upgrade b3348.3

- Bring the Logan-Sprigg #2 138 kV circuit in and out of Tin Branch station by constructing approximately 1.75 miles of new overhead double circuit 138 kV line. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW. - 11/1/2026 - $8.58M

432) Baseline Upgrade b3348.4

- Logan-Wyoming No. 1 circuit in and out of the proposed Argyle station. Double circuit T3 series lattice towers will be used along with 795,000 cm ACSR 26/7 conductor. One shield wire will be conventional 7 #8 ALUMOWELD, and one shield wire will be OPGW. - 11/1/2026 - $7.70M

433) Baseline Upgrade b3348.5

- Rebuild approximately 10 miles of 46 kV line between Becco and the new Argyle substation. Retire approximately 16 miles of 46 kV line between the new Argyle substation and Chauncey station. - 11/1/2026 - $33.71M

434) Baseline Upgrade b3348.6

- Adjust relay settings due to new line terminations and retirements at Logan, Wyoming, Sprigg, Becco and Chauncey stations. - 11/1/2026 - $0.23M

435) Baseline Upgrade b3349

- Replace Bellefonte 69 kV risers on the section between Bellefonte TR #3 and 69 kV Bus #2. - 6/1/2026 - $0.54M

436) Baseline Upgrade b3351

- Replace the 69 kV in-line switches at Monterey 69 kV substation. - 6/1/2026 - $0.00M

437) Baseline Upgrade b3352

- Replace MOAB W, MOAB Y, line and bus side jumpers of both W and Y at 47th Street 69 kV station. Upgrade the 69 kV strain bus between MOABs W and Y to 795 KCM AAC. Change the connectors on the tap to MOAB X1 to accommodate the larger 795 KCM AAC. - 6/1/2026 - $0.00M

438) Baseline Upgrade b3353.1

- Allen substation: Rebuild Allen station to the northwest of its current footprint utilizing a standard air-insulated substation with equipment raised by 7’ concrete platforms and control house raised by a 10’ platform to mitigate flooding concerns. Install five 69 kV 3000A 40 kA circuit breakers in a ring bus (operated at 46 kV) configuration with a 13.2 MVAR capacitor bank. Existing Allen station will be retired (does not include the distribution cost). Distribution scope of work: Install 69/46 kV-12 kV 20 MVA transformer along with 2-12 kV breakers on 7’ concrete platforms (conversion of S2405.1). - 12/1/2026 - $10.55M

439) Baseline Upgrade b3353.2

- Allen-East Prestonsburg: A 0.20 mile segment of this 46 kV line will be relocated to the new station (SN/SE/WN/WE: 53/61/67/73MVA). (Conversion of S2405.2) - 12/1/2026 - $0.33M

440) Baseline Upgrade b3353.3

- McKinney-Allen: The new line extension will walk around the south and east sides of the existing Allen station to the new Allen station being built in the clear. A short segment of new single circuit 69 kV line and a short segment of new double circuit 69 kV line (both operated at 46 kV) will be added to the line to tie into the new Allen station bays. (Conversion of S2405.3) - 12/1/2026 - $1.95M

441) Baseline Upgrade b3353.4

- Stanville-Allen: A segment of this line will have to be relocated to the new station (SN/SE/WN/WE: 50/50/63/63MVA). (Conversion of S2405.4) - 12/1/2026 - $0.17M

442) Baseline Upgrade b3353.5

- Allen-Prestonsburg: 0.25 mile segment of this existing single circuit will be relocated. The relocated line segment will require construction of one custom self-supporting double circuit dead-end structure and single circuit suspension structure. A short segment of new double circuit 69 kV line (energized at 46 kV) will be added to tie into the new Allen station bays, which will carry Allen-Prestonsburg 46 kV and Allen-East Prestonsburg 46 kV lines. A temporary 0.15 mile section double circuit line will be constructed to keep Allen-Prestonsburg and Allen-East Prestonsburg 46 kV lines energized during construction. (Conversion of S2405.5) - 12/1/2026 - $2.66M

443) Baseline Upgrade b3353.6

- Remote end work will be required at Prestonsburg, Stanville and McKinney stations. (Conversion of S2405.6) - 12/1/2026 - $0.34M

444) Baseline Upgrade b3358

- Install a 69 kV 11.5 MVAR capacitor at Biers Run station. - 6/1/2026 - $0.85M

445) Baseline Upgrade b3359

- Rebuild approximately 2.3 miles of the existing North Van Wert Sw-Van Wert 69 kV line utilizing 556 ACSR conductor. - 6/1/2026 - $6.20M

446) Baseline Upgrade b3360

- Replace Thelma Transformer #1 with a 138/69/46 kV 130/130/90 MVA transformer and replace 46 kV risers and relaying toward Kenwood substation. Existing TR#1 to be used as spare. - 12/1/2026 - $3.54M

447) Baseline Upgrade b3361

- Rebuild Prestonsburg-Thelma 46 kV circuit, approximately 14 miles. Retire Jenny Wiley SS. - 12/1/2026 - $33.01M

448) Baseline Upgrade b3362

- Rebuild approximately 3.1 miles of the overloaded conductor on the existing Oertels Corner-North Portsmouth 69 kV line utilizing 556 ACSR. - 6/1/2026 - $8.00M

449) Baseline Upgrade b3370

- Upgrade terminal equipment on the Loretto - Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor - 6/1/2026 - $0.80M

450) Baseline Upgrade b3371

- Rebuild approx. 3.6 miles of 875 (N. Boyertown - W. Boyertown). Upgrade terminal equipment (circuit breaker, disconnect switches, substation conductor) and relays at N. Boyertown and W. Boyertown substation - 6/1/2026 - $8.79M

451) Baseline Upgrade b3372

- East Towanda – North Meshoppen 115 kV Line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS - 6/1/2026 - $6.66M

452) Baseline Upgrade b3373

- Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line - 6/1/2026 - $0.30M

453) Baseline Upgrade b3374

- Replace Five Atlantic 34.5 kV breakers (J36, BK1A, BK1B, BK3A and BK3B) with 63kA rated breakers and associated equipment - 6/1/2026 - $3.50M

454) Baseline Upgrade b3375

- Replace Six Werner 34.5 kV breakers (E31A_Prelim, E31B_Prelim, V48 future, W101, M39 and U99) with 40 kA rated breakers and associated equipment.. - 6/1/2026 - $4.20M

455) Baseline Upgrade b3376

- Replace One Freneau 34.5 kV breaker (BK6) with 63 kA rated breakers and associated equipment - 6/1/2026 - $0.70M

456) Baseline Upgrade b3664

- Juniata: Replace the limiting 230 kV T2 transformer leads, bay conductor and bus conductor with double bundle 1590 ACSR. Replace the limiting 1200 A MODs on the Bus tie breaker with 3000 A MODs - 6/1/2026 - $0.68M

457) Baseline Upgrade b3665

- Replace several pieces of 1033.5 AAC substation conductor at East Towanda 230 kV Substation (on East Towanda-Canyon 230 kV Line terminal) - 6/1/2026 - $0.41M

458) Baseline Upgrade b3666

- Marshall 230 kV Substation: Install dual reactors and expand existing ring bus - 6/1/2026 - $5.83M

459) Baseline Upgrade b3667

- Pierce Brook Substation: Install second 230/115 kV transformer - 6/1/2026 - $5.07M

460) Baseline Upgrade b3668

- Upgrade Windy Edge 115 kV substation conductor to increase ratings of the Windy Edge-Chesco Park 110501 circuit. - 6/1/2026 - $0.50M

461) Baseline Upgrade b3669.1

- Replace terminal equipment (stranded bus, disconnect switch and circuit breaker) at Church substation (Townsend-Church 138 kV). - 12/1/2026 - $1.00M

462) Baseline Upgrade b3669.2

- Replace terminal equipment (circuit breaker) at Townsend substation (Townsend-Church 138 kV). - 12/1/2026 - $0.45M

463) Baseline Upgrade b3670

- Upgrade terminal equipment on the Loretto-Fruitland 69 kV circuit: Replace the 477 ACSR stranded bus on the 6711 line terminal inside Loretto substation and the 500 SDCU stranded bus on the 6711 line terminal inside Fruitland substation with 954 ACSR conductor. - 6/1/2026 - $0.80M

464) Baseline Upgrade b3672

- East Towanda-North Meshoppen 115 kV line: Rebuild 2.5 miles of 636 ACSR with 1113 ACSS conductor using single circuit construction. Upgrade all terminal equipment to the rating of 1113 ACSS. - 6/1/2026 - $6.66M

465) Baseline Upgrade b3673

- Replace the relay panels at Bethlehem 33 46 kV substation on the Cambria Prison line. - 6/1/2026 - $0.30M

466) Baseline Upgrade b3677

- Rebuild a 13 mile section of 138 kV line 0108 between LaSalle and Mazon with 1113 ACSR or higher rated conductor. The 13 mile portion of line 7713 from Oglesby (future Corbin) to Mazon that shares double circuit towers with line 0108 will also be reconductored due to the rebuild. - 11/1/2026 - $42.06M

467) Baseline Upgrade b3678

- Expand Galion 138 kV substation; Install 100 MVAR reactor, associated breaker and relaying. - 11/1/2026 - $5.74M

468) Baseline Upgrade b3679

- Replace West Fremont 138/69 kV TR2 with a transformer having additional high-side taps. - 11/1/2026 - $6.44M

469) Baseline Upgrade b3680

- At Sanborn, replace limiting substation conductors on Ashtabula 138 kV exit to make transmission line conductor the limiting element. - 6/1/2026 - $0.30M

470) Baseline Upgrade b3681

- Upgrade the Shingletown #82 230-46 kV transformer circuit by installing a 230 kV breaker and disconnect switches, removing existing 230 kV switches, replacing 46 kV disconnect switches, replacing limiting substation conductor, and installing/replacing relays. - 6/1/2026 - $1.66M

471) Baseline Upgrade b3682

- Install a second 345/138 kV transformer at Hayes, 448 MVA nameplate rating. Add one 345 kV circuit breaker (3000A) to provide transformer high-side connection between breaker B-18 and the new breaker. Connect the new transformer low side to the 138 kV bus. Add one 138 kV circuit breaker (3000A) at Hayes 138 kV substation between B-42 and the new breaker. Relocate the existing 138 kV No. 1 capacitor bank between B-42 and the new breaker. Protection per FE standard. - 6/1/2026 - $7.59M

472) Baseline Upgrade b3683

- Reconductor the existing 556.5 ACSR line segments (3.49 miles) on the Messick Road-Ridgeley WC4 138 kV line with 954 45/7 ACSR to achieve 308/376 MVA SN/SE and 349/445 MVA WN/WE ratings. Replace the remote end equipment for the Messick Road-Ridgeley WC4 138 kV line. The total length of the line is 5.02 miles. - 6/1/2026 - $11.20M

473) Baseline Upgrade b3684

- Rebuild 12.4 miles of 115 line #126 segment from Earleys to Kelford with a summer emergency rating of 262 MVA. Replace structures as needed to support the new conductor. Upgrade breaker switch 13668 at Earleys from 1200 A to 2000 A. - 6/1/2026 - $18.75M

474) Baseline Upgrade b3685

- Install a 33 MVAR cap bank at Cloud 115 kV bus along with a 115 kV breaker. Add 115 kV circuit breaker for 115 kV line #38. - 6/1/2026 - $1.50M

475) Baseline Upgrade b3686

- Purchase land close to the bifurcation point of 115 kV line #4 (where the line is split into two sections) and build a new 115 kV switching station called Duncan Store. The new switching station will require space for an ultimate transmission interconnection consisting of a 115 kV six-breaker ring bus (with three breakers installed initially). - 12/1/2026 - $16.00M

476) Baseline Upgrade b3687

- Rebuild approximately 15.1-mile-long line segment between 115 kV line #183 Bristers and Minnieville D.P. with 2-768 ACSS and 4000 A supporting equipment from Bristers to Ox to allow for future 230 kV capability of 115 kV line #183. The continuous summer normal rating will be 523 MVA from Ox-Minnieville. The continuous summer normal rating will be 786 MVA from Minnieville-Bristers. - 6/1/2026 - $30.00M

477) Baseline Upgrade b3688

- Replace the 4/0 SDCU stranded bus with 954 ACSR and a 600 A disconnect switch with a 1200 A disconnect switch on the 6716 line terminal inside Todd substation (on the Preston-Todd 69 kV circuit). - 6/1/2026 - $0.75M

478) Baseline Upgrade b3689.1

- Reconductor approximately 24.42 miles of 230 kV line #2114 Remington CT-Elk Run-

Gainesville to achieve a summer rating of 1574 MVA by fully reconductoring the line and upgrading the wave trap and substation conductor at Remington CT and Gainesville. - 6/1/2026 - $28.99M

479) Baseline Upgrade b3689.2

- Replace 230 kV breakers SC102, H302, H402 and 218302 at Brambleton substation with 4000A 80 kA breakers and associated equipment including breaker leads as necessary to address breaker duty issues identified in short circuit analysis. - 6/1/2026 - $1.69M

480) Baseline Upgrade b3690

- Reconductor approximately 1.07 miles of 230 kV line #2008 segment from Cub Run-Walney to achieve a summer rating of 1574 MVA. Replace line switch 200826 with a 4000A switch. - 6/1/2026 - $2.03M

481) Baseline Upgrade b3692

- Rebuild approximately 27.7 miles of 500 kV transmission line from Elmont to Chickahominy with current 500 kV standards construction practices to achieve a summer rating of 4330 MVA. - 6/1/2026 - $58.16M

482) Baseline Upgrade b3693

- Expand substation and install approximately 294 MVAR cap bank at 500 kV Lexington substation along with a 500 kV breaker. Adjust the tap positions associated with the two 230/69 kV transformers at Harrisonburg to neutral position and lock them. - 11/1/2026 - $5.86M

483) Baseline Upgrade b3694.1

- Convert line #29 Aquia Harbor to Possum Point to 230 kV (Extended line #2104) and swap line #2104 and converted line #29 at Aquia Harbor backbone termination. Upgrade terminal equipment at Possum Point to terminate converted line 29 (now extended line #2104). (Line #29 from Fredericksburg to Aquia Harbor is being rebuilt under baseline b2981 to 230kV standards.) - 6/1/2026 - $9.39M

484) Baseline Upgrade b3694.10

- Reconductor approximately 2.9 miles of 230 kV line #211 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA. - 6/1/2026 - $4.91M

485) Baseline Upgrade b3694.11

- Reconductor approximately 2.9 miles of 230 kV line #228 Chesterfield-Hopewell to achieve a minimum summer emergency rating of 1046 MVA. - 6/1/2026 - $4.91M

486) Baseline Upgrade b3694.12

- Upgrade equipment at Chesterfield substation to not limit ratings on lines 211 and 228. - 6/1/2026 - $0.76M

487) Baseline Upgrade b3694.13

- Upgrade equipment at Hopewell substation to not limit ratings on lines 211 and 228. - 6/1/2026 - $1.71M

488) Baseline Upgrade b3694.2

- Upgrade Aquia Harbor terminal equipment to not limit 230 kV line #9281 conductor rating. - 6/1/2026 - $0.63M

489) Baseline Upgrade b3694.3

- Upgrade Fredericksburg terminal equipment by rearranging 230 kV bus configuration to terminate converted line 29 (now becoming 9281). The project will add a new breaker at the 230 kV bay and reconfigure line termination of 230 kV lines #2157, #2090 and #2083. - 6/1/2026 - $2.73M

490) Baseline Upgrade b3694.4

- Reconductor/rebuild approximately 7.6 miles of 230 kV line #2104 Cranes Corner-Stafford to achieve a summer rating of 1047 MVA(1). Reconductor/rebuild approximately 0.34 miles of 230 kV line #2104 Stafford-Aquia Harbor to achieve a summer rating of 1047 MVA. Upgrade terminal equipment at Cranes Corner to not limit the new conductor rating. - 6/1/2026 - $19.60M

491) Baseline Upgrade b3694.5

- Upgrade wave trap and line leads at 230 kV line #2090 Ladysmith CT terminal to achieve 4000A rating. - 6/1/2026 - $0.15M

492) Baseline Upgrade b3694.6

- Upgrade Fuller Road substation to feed Quantico substation via 115 kV radial line. Install four-breaker ring and break 230 kV line #252 into two new lines: 1) #252 between Aquia Harbor to Fuller Road and 2) #9282 between Fuller Road and Possum Point. Install a 230/115 kV transformer which will serve Quantico substation. - 6/1/2026 - $24.16M

493) Baseline Upgrade b3694.7

- Energize in-service spare 500/230 kV Carson Tx#1. - 6/1/2026 - $0.00M

494) Baseline Upgrade b3694.8

- Partial wreck and rebuild 10.34 miles of 230 kV line #249 Carson-Locks to achieve a minimum summer emergency rating of 1047 MVA. Upgrade terminal equipment at Carson and Locks to not limit the new conductor rating. - 6/1/2026 - $22.01M

495) Baseline Upgrade b3694.9

- Wreck and rebuild 5.4 miles of 115 kV line #100 Locks-Harrowgate to achieve a minimum summer emergency rating of 393 MVA. Upgrade terminal equipment at Locks and Harrowgate to not limit the new conductor rating and perform line #100 Chesterfield terminal relay work. - 6/1/2026 - $9.10M

496) Baseline Upgrade b3697

- Replace station conductor and metering inside Whitpain and Plymouth substations to increase the ratings of the 220-13/220-14 Whitpain-Plymouth 230 kV line facilities. - 6/1/2025 - $0.62M

497) Baseline Upgrade b3698

- Reconductor the 14.2 miles of the existing Juniata-Cumberland 230 kV line with 1272 ACSS/TW HS285 "Pheasant" conductor. - 12/31/2023 - $8.99M

498) Baseline Upgrade b3702

- Install one 13.5 Ohm series reactor to control the power flow on the 230 kV line #2054 from Charlottesville substation to Proffit Rd 230 kV line. - 6/1/2023 - $11.38M

Revision History:

Version: 1

Date: 3/1/2023

Approver: Sami Abdulsalam, Manager Transmission Planning

DATA REQUEST

KPSC 1_12 Refer to the IRP, Volume A, Section 3.6.8, pages 73–80.
a. Explain which projects will require a Certificate of Public Convenience and Necessity (CPCN) and the anticipated time that the applications for CPCNs will be filed with the Commission.
b. Provide a transmission system map showing where these projects are located including the proposed additions or retirements of facilities.

RESPONSE

a. and b. Please see KPCO_R_KPSC_1_12_Attachment1 for the requested information.

Witness: Kamran Ali

Projects Identified in Section 3.6.8 Requiring a CPCN

Application Has Been Filed

Project	Case No.	Map on Page XX of Attachment
Hazard-Wooton	2017-00238 and 2019-00154	2-6
Kewanee-Enterprise Park	2020-00062	7
Garrett Area Improvement	2021-00346	8-11
Wooton-Stinnett	2022-00118	12-14
New Camp Loop (Belfry)	2023-00040	15-20

Application To Be Filed

Project	Anticipated Filing Date	Map on Page XX of Attachment
Prestonburg-Thelma Rebuild and Thelma Transformer Replacement	Q2 2025	21-27
Breaks - Dorton Conversion	Q2 2026	28-30
Elwood Station Improvement	Q1 2028	31-34
Stinnett-Pineville	Q2 2029	35-37
Middle Creek Prsetonburg	Q2 2029	38-39

Cancelled

Middle Creek Battery Storage System

AEP Transmission Zone

B2761.1 – Scope Clarification /Cost Update

Previously Presented: 10/6/2016 SRRTEP

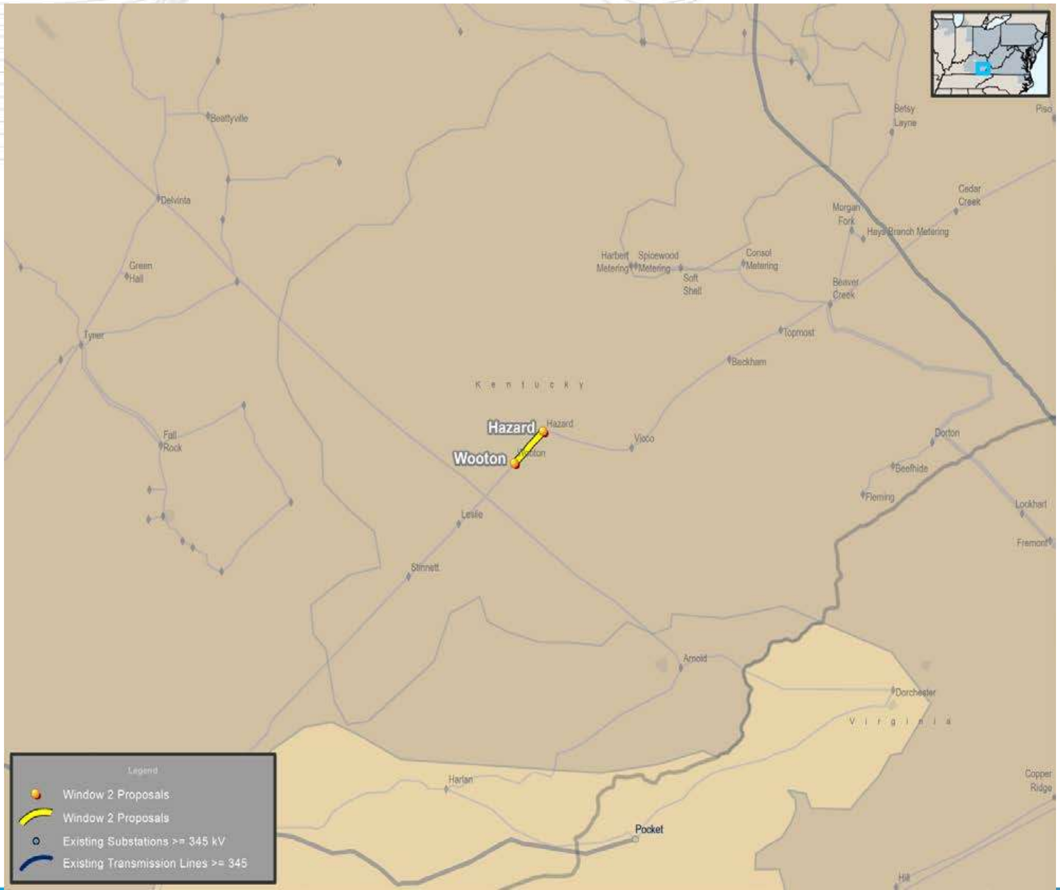
Original Scope Description: Replace the Hazard 161/138 kV Transformer

Original Estimated Cost: $2.3 M

New Scope Description: Replace and relocate the Hazard 161/138 kV Transformer and circuit breaker 'M'. Upgrade protection scheme on the new Transformer including installation of low side breaker.

New Estimated Cost: $ 3.8 M

Required IS Date: 6/1/2021



AEP Transmission Zone: Baseline
Hazard – Wooton 161kV Circuit

B2761.3 –Scope Clarification/Cost Update
Previously Presented: 9/11/2017 SRRTEP

Original Scope Description: Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating).
Original Estimated Cost: $16.48 M

New Scope Description: Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating). Replace line relaying and associated termination equipment .
New Estimated Cost: $16.8 M

Required In-service: 6/1/2021

AEP Transmission Zone: Supplemental Hazard Station

Previously Presented:11/2/2017 SRRTEP

Problem Statement:

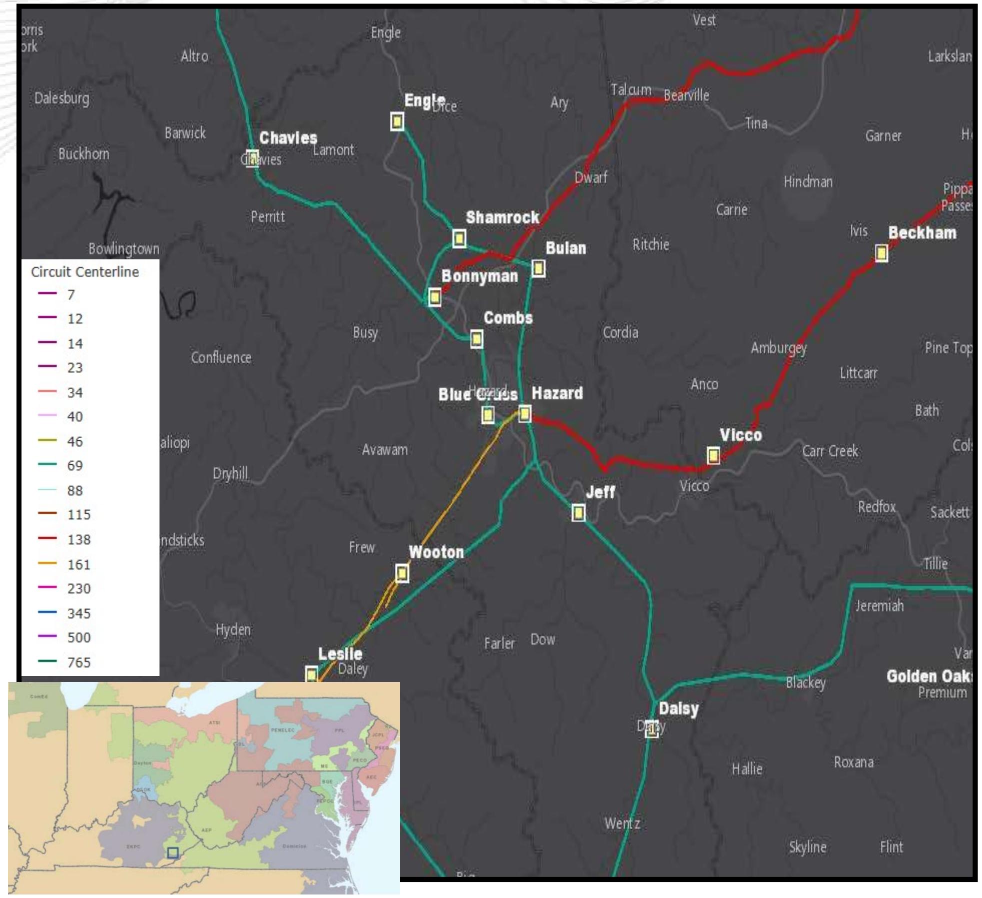
Equipment Material/Condition/Performance/Risk:

Circuit breakers S (1100A, 11.3kA) and E (1800A, 27kA) at Hazard station are FK type breakers all over 40 years old. Circuit breaker F at Hazard is a 1200A, 31.5kA CG type breaker. These are oil breakers that have come more difficult to maintain due to the required oil handling. In general, oil spills occur often during routine maintenance and failures with these types of breakers. Other drivers include PCB content, damage to bushings and number of fault operations exceeding the recommendations of the manufacturer. Breakers S, E, and F have experienced 82, 184, and 193 fault operations respectively, well above the manufactures recommendation of 10.

Circuit breaker M (2000A, 40kA) will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761) in order to limit outage times. The breaker is an SF6-gas breaker, 29 years old and has experienced 21 fault operations, which exceeds the manufacturer recommendation of 10.

Transformer #1 (1974 vintage, 50 MVA) and #2 (1973 vintage, 130 MVA) show dielectric breakdown (insulation), accessory damage (bushings/windings) and short circuit breakdown (due to amount of through faults). Transformer #1 also shows signs of corrosion on radiators as well as oil leaks.

Circuit Switcher BB a MARK V unit which have presented AEP with a large amount of failures and mis-operations. AEP has determined that all MARK V's will be replaced and upgraded with the latest AEP cap-switcher design standard. Capacitor bank BB will need to be relocated in association with the baseline project to replace the existing 161/138 kV transformer at Hazard station (b2761).



AEP Transmission Zone: Supplemental Hazard Station

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Capacitor switcher CC has oil leaks on all three phases and cannot be repaired. Capacitor bank CC was a non standard design and its components (fuses and cans) have begun to fail.

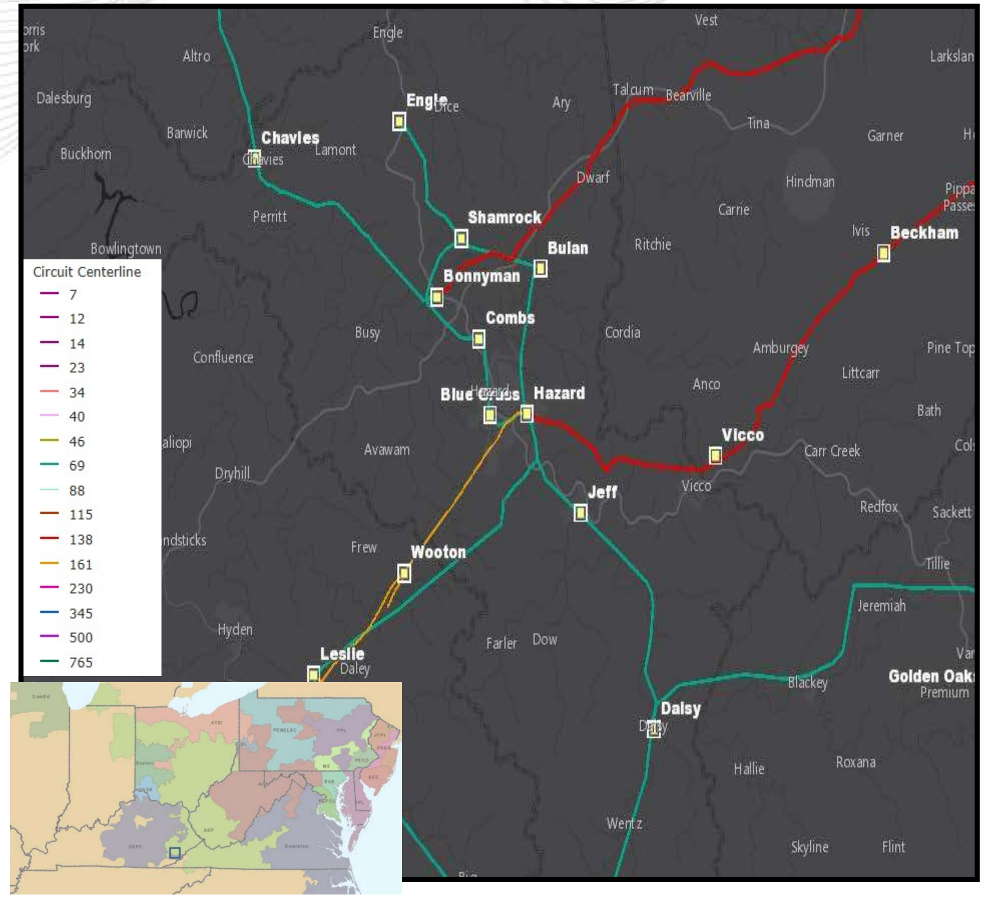
Safety concerns associated with existing equipment platforms at the station will also be addressed. The majority of the platforms at the station were field designed with thought of access, not safety, adequate clearances, or structural integrity in mind. Drainage issues at the station will also be addressed. Water from an adjacent parking lot and an incorrectly sloped 69 kV yard is causing water to pool on the fence line at Hazard Station.

<u>Operational Flexibility and Efficiency</u>

A 138 kV circuit breaker will be added at Hazard station on the line exit towards Beckham station, along with a circuit switcher and low side breaker on transformer #1 to separate three dissimilar zones of protection. The 138 kV bus, the Hazard – Beckham 138 kV line, and the 138/69 kV transformer #1 are all on the same protection zone. This can lead to mis-operations and over tripping.

138 kV circuit switchers will be added to transformer #2 and #4, as well as low side breakers on transformer #2, #3, and #4 to separate four dissimilar zones of protection.

Transmission Operations has requested a 69 KV bus tie circuit breaker be installed to improve operational flexibility to the 69 kV networks served out of Hazard. The 69 kV tie breaker will also help facilitate the retirement of Capacitor AA which is currently located off the line to Bonnyman, is beginning to show issues, and requires its VBM type cap switcher replaced. Tying the 69 kV buses together requires the 138/69 kV transformers to be the same size to avoid circulating currents and to be able to serve the 69 kV area independently for loss of one.



AEP Transmission Zone: Supplemental Hazard Station

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Selected Solution:

Install a new 3000A 40 kA 138 kV circuit breaker at Hazard station on the line exit towards Beckham station. **(s1412.1)**

Add a 138 kV circuit switcher to the high side of transformer #4. **(s1412.2)**

Replace 138 kV capacitor bank and switcher BB with a new switcher and 43.2 MVAR capacitor bank. **(s1412.3)**

Replace 138/69 kV transformers #1 and #2 with new 138/69 kV 130 MVA transformers with 138 kV circuit switchers on the high side and 3000A 40 kA 69 kV breakers on the low side. **(s1412.4)**

Replaces 69 kV circuit breakers S, E, and F with 3000A 40 kA 69 kV circuit breakers with a bus tie 3000A 69 kV circuit breaker being installed between the existing 69 kV box bays. **(s1412.5)**

Replace 69 kV capacitor bank and switcher CC with a new switcher and 28.8 MVAR capacitor bank. 69 kV capacitor bank and switcher AA will be retired.

Replace 161 kV circuit breaker M towards Wooton with a 161 kV 3000 A 40 kA breaker. **(s1412.6)**

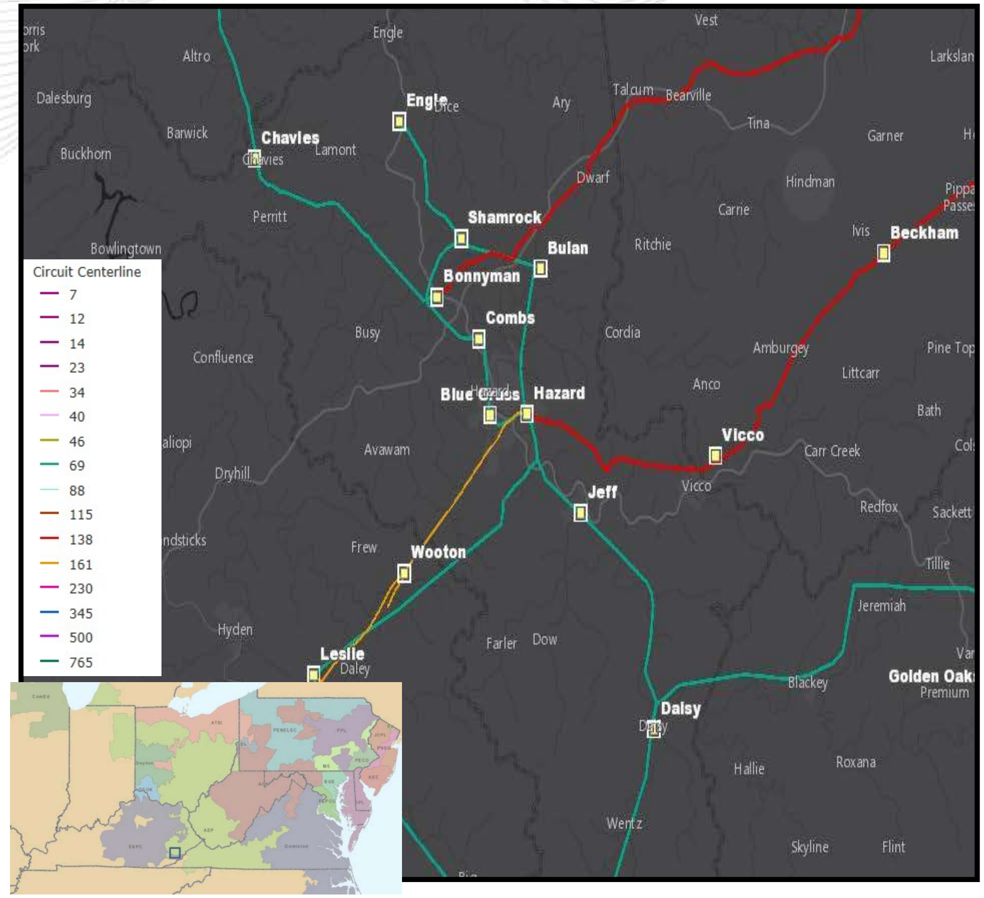
Add a 3000A 40 kA 138 kV circuit breaker to the low side of 161/138 kV transformer #3. **(s1412.7)**

Address safety and access issues associated with existing equipment platforms and drainage issues at the station. **(s1412.8)**

Estimated Transmission Cost: $20.0M

Projected In-service: 12/31/2019

Project Status: Scoping



AEP Transmission Zone: Baseline
Pike County, KY

Additional Scope for Project B3087
Criteria: FERC 715 Planning Criteria Violation
Model Used for Analysis: 2023 Winter RTEP

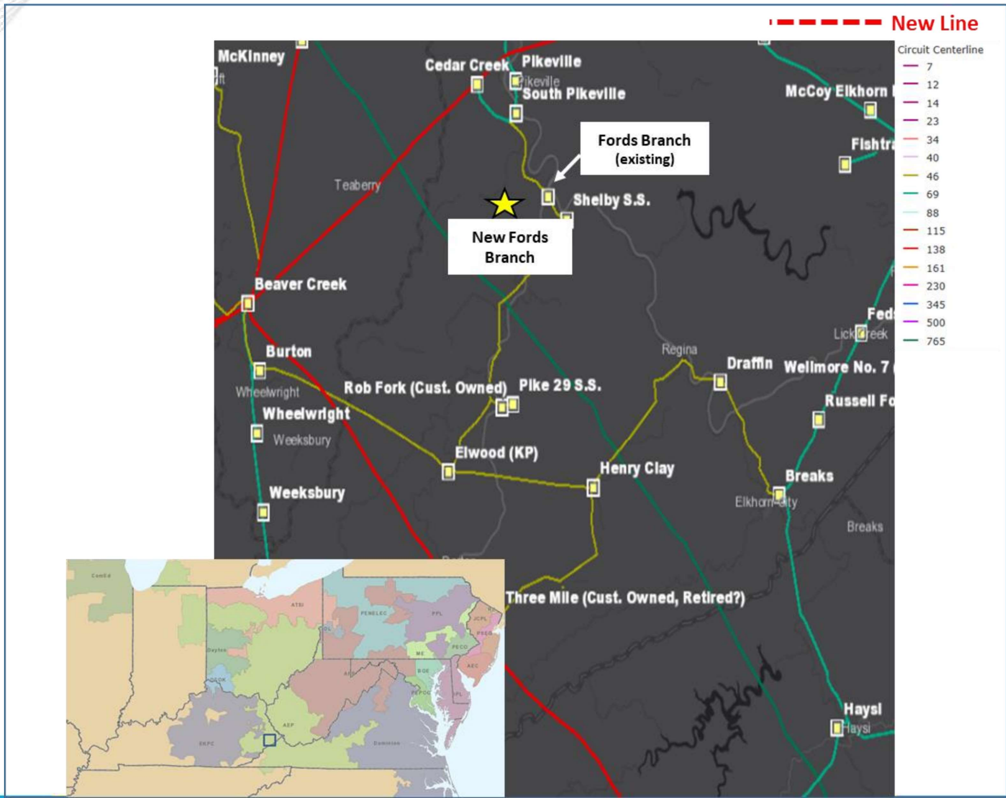
Existing Scope: (Presented: 11/29/2018, 10/25/2019 SRRTEP**):**
Construct a new greenfield station to the west (~1.5 mi.) of the existing Fords Branch Station, potentially in/near the new Kentucky Enterprise Industrial Park. This new station will consist of 4 -138 kV breaker ring bus and two 30 MVA 138/34.5 kV transformers. The existing Fords Branch Station will be retired. (**B3087.1**)
Estimated Cost: $2.8 M
Construct approximately 5 miles of new double circuit 138 kV line in order to loop the New Fords Branch station into the existing Beaver Creek – Cedar Creek 138 kV circuit. (**B3087.2**) **Estimated Cost: $19.9 M**
Remote end work will be required at Cedar Creek Station. (**B3087.3**) **Estimated Cost: $ 0.5 M**

Additional Scope: Install a 28.8MVar switching shunt at the new Fords Branch substation (**B3087.4**)
Estimated Cost: $ 0.5 M

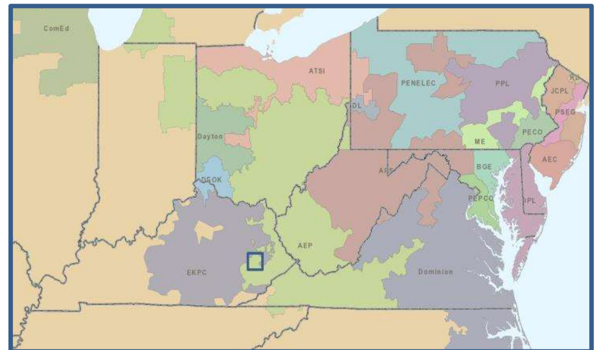
Reason for the additional scope:

- For the N-1-1 Loss of Beaver Creek Transformer #1 and the loss of Cedar Creek – Johns Creek 138kV line, voltage magnitude violations are identified at New Fords Branch substation (0.90 pu), Cedar Creek 138kV (0.90 pu).
- For the N-1-1 Loss of Beaver Creek – Kewanee (New Fords Branch) 138kV and Cedar Creek – Johns Creek 138kV line, voltage magnitude violations issues are identified at the new Fords Branch substation (0.87 pu), Cedar Creek 138kV (0.87pu), Cedar Creek 69kV (0.90 pu).

Required In-service: 12/1/2023
Projected In-service: 09/31/2022
Project Status: Scoping



AEP Transmission Zone M-3 Process
Garrett Area Improvements



Need Number: AEP-2019-AP017

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/10/2020

Previously Presented:
Needs Meeting 6/17/2019
Solutions Meeting 2/21/2020

Project Driver:
Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Beaver Creek – McKinney #1 46 kV Circuit

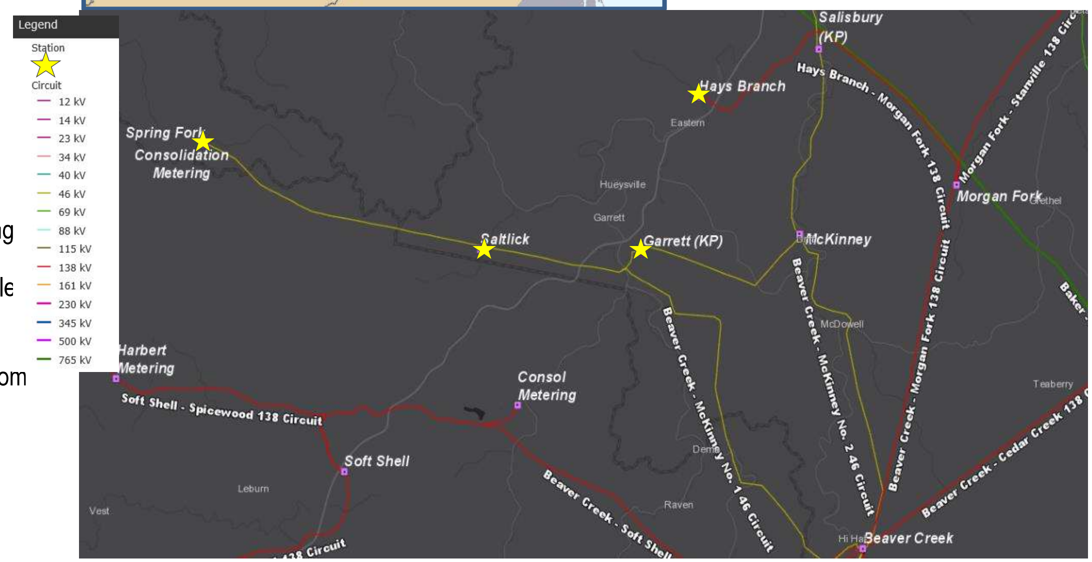
- From 2016-2018, the approximately 24.6 mile Beaver Creek – McKinney #1 46 kV circuit has experienced 22 outages.
- The circuit is comprised of 152 structures, the majority of which are wood structures dating back to 1929 (22/152, 14%) and 1949 (61/152, 40%).
- There are 142 open conditions along the 24.6 mile long line. These include damaged pole and cross-arms, conductor/shield wires, and guy anchor/knee/vee braces.

Hays Branch Station

- Hays Branch serves a ~30 MW gas compressing operation that is currently radially fed from a ~8.25 mile line out of Morgan Fork station.

Saltlick Station

- Saltlick serves an EKPC co-op that is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.



AEP Transmission Zone M-3 Process
Garrett Area Improvements

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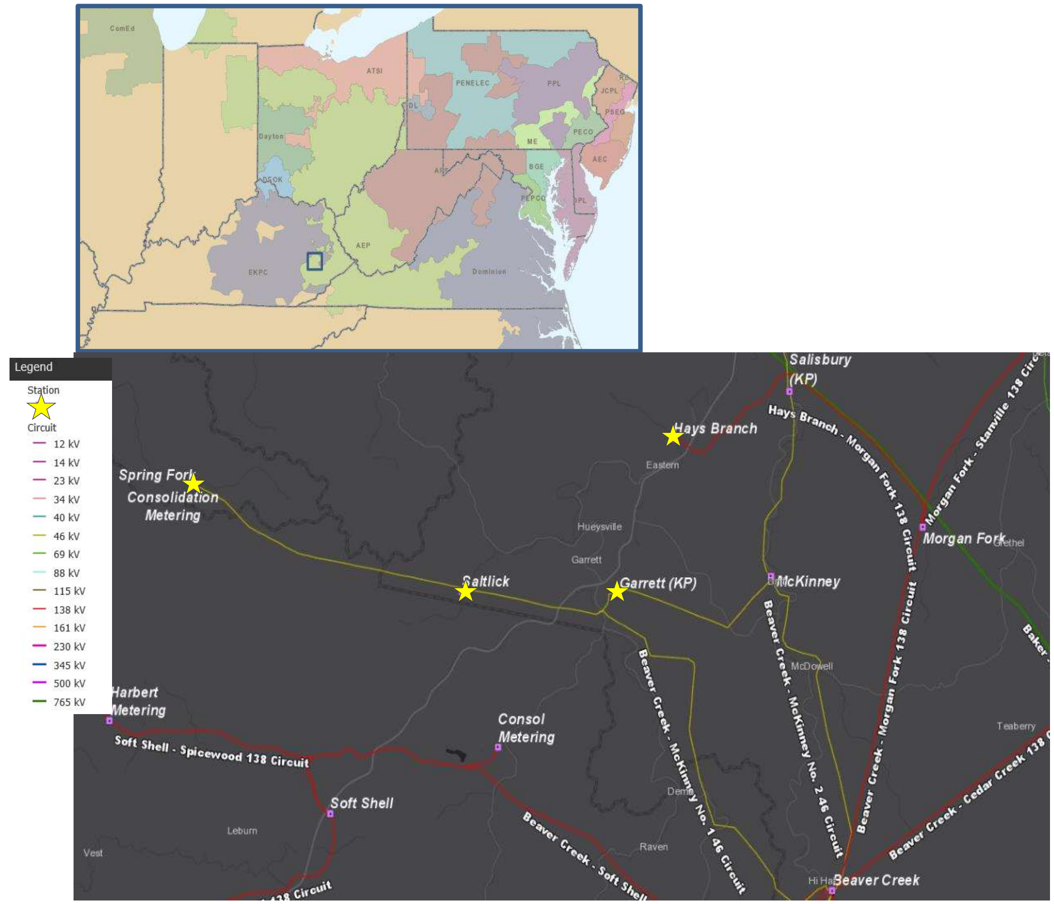
Spring Fork

- Spring Fork station serves KPCo distribution customers and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.

Consolidation Metering

- Consolidation Metering station serves a mining operation and is currently radially fed off the Beaver Creek – McKinney 46 kV circuit.



AEP Transmission Zone M-3 Process
Garrett Area Improvements

Need Number: AEP-2019-AP017
Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/10/2020

Selected Solution:
Construct ~~~9.3~~ 10.3 miles of single circuit 138kV from Soft Shell to Garrett picking up Salt Lick Co-op via Snag Fork along the way. Complete associated remote end relaying.
(**S2188.1**) **Estimated Cost: $35.3M**

Construct ~3~~.5~~ miles of single circuit 138kV from the Eastern station to Garrett station. A short extension will be required from the new station to the existing Hays Branch metering point. Construct short extension to existing Morgan Fork – Hays Branch 138 kV circuit from Eastern station
(**S2188.2**) **Estimated Cost: $11.5M**

Double circuit cut into existing Hays Branch - Morgan Fork line to tie into new Eastern station. ~~Hays Branch S.S PoP switch. Installation of a new heavy double circuit dead-end tap structure on the existing Hays Branch – Morgan Fork 138kV Line (Due to unequal loading on the transmission line).~~
(**S2188.3**) **Estimated Cost: $1.3M**

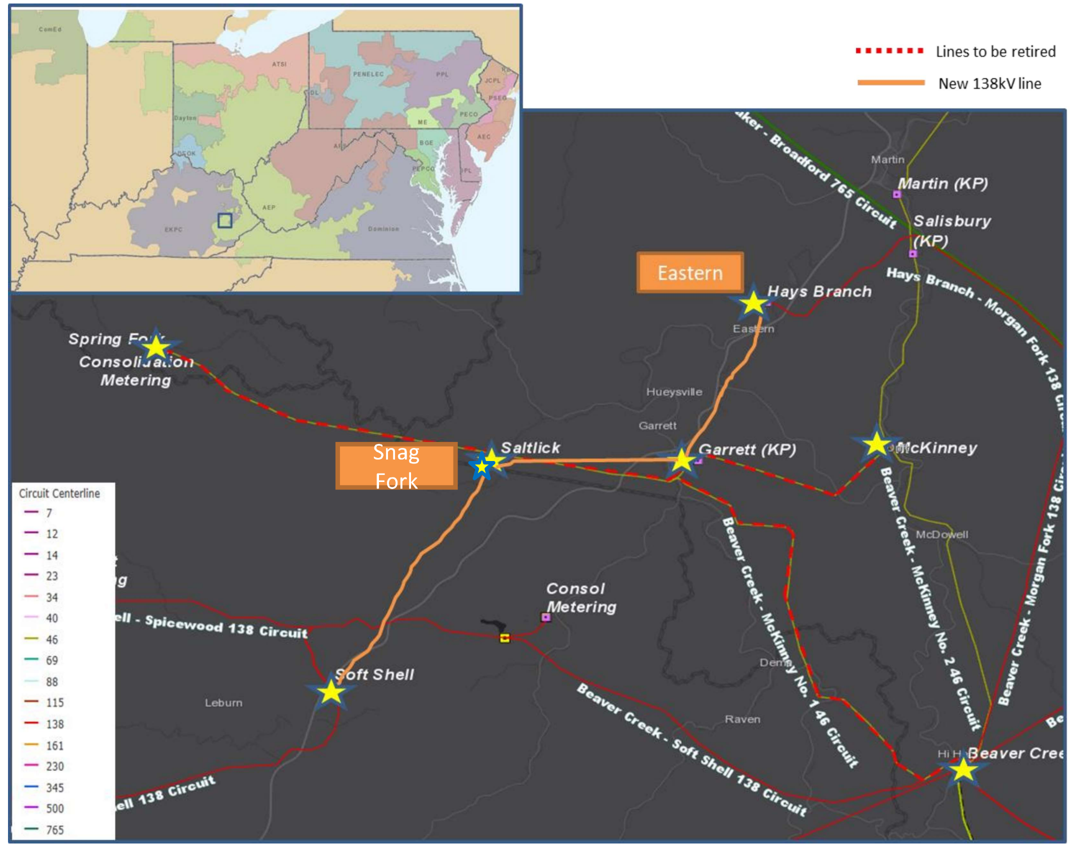
Construct ~~~0.25~~ 1.4 mi of double circuit 138kV line between ~~Hays Branch S.S –~~ Eastern and the tap point on the Morgan Fork-Hays Branch line. The proposed line will establish a direct feed to Hays Branch from Eastern and establishing a through path line between Eastern and Morgan Fork. ~~Installation of 3 double circuit suspension structures one of which is a custom pole structure.~~
(**S2188.4**) **Estimated Cost: $1.6M**

New ~~PoP switch structure~~ relaying at Hays Branch to accommodate new line from Eastern station
(**S2188.5**) **Estimated Cost: $0.5M**

Expand the Garrett station, Install ~~a 138kV three breaker ring bus (If space becomes a constraint, we should look at installing~~ a straight bus arrangement with two 138 kV breakers and a circuit switcher on the high side of the transformer~~)~~, 138/12kV 30 MVA transformer
(**S2188.6**) **Estimated Cost: ~~$5.8M~~ $0.0M**

Establish a new 138 kV substation Eastern south of the existing Hays Branch station. Install ~~two~~ three 138kV breakers (3000A 40kA) at the new Eastern station ~~on exits toward Morgan Fork and Garrett station~~ in a ring bus arrangement.
(**S2188.7**) **Estimated Cost: $6 M**

Establish Snag Fork S.S. Install a 3 way phase over phase motorized (automated) switching structure near Saltlick to serve the EKPC co-op.
(**S2188.8**) **Estimated Cost: $1.1 M**



AEP Transmission Zone M-3 Process
Garrett Area Improvements

Proposed Solution (Cont.):

Move the existing 69kV rated CB G to the Beaver Creek – McKinney #2 circuit exit at McKinney substation. (**S2188.9**) **Estimated Cost: $0.0 M**

Install a 138kV breaker (3000A 40kA) with an exit towards Garrett station (via Snag Fork) at Softshell substation. (**S2188.10**) **Estimated Cost: ~~$0.8 M~~ $0.0M**

Retire the ~25 miles of the 46kV Beaver Creek – McKinney #1 46 KV circuit. Retire Spring Fork Tap. (**S2188.11**) **Estimated Cost: $17.3 M**

Ancillary Benefits: Removal of obsolete ~25 mi of 46kV network.

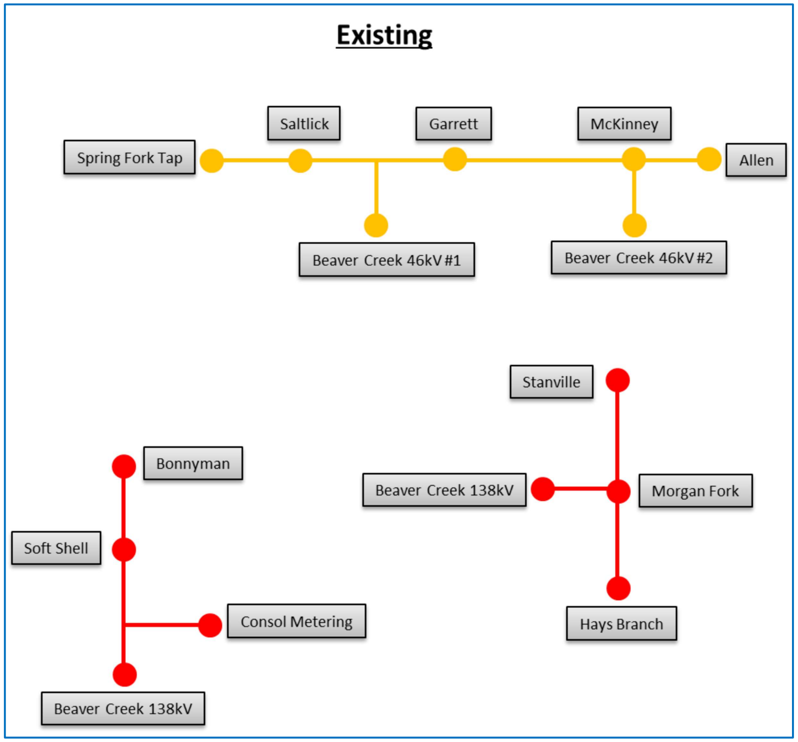
Estimated Cost: ~~$81.2M~~ $74.6M

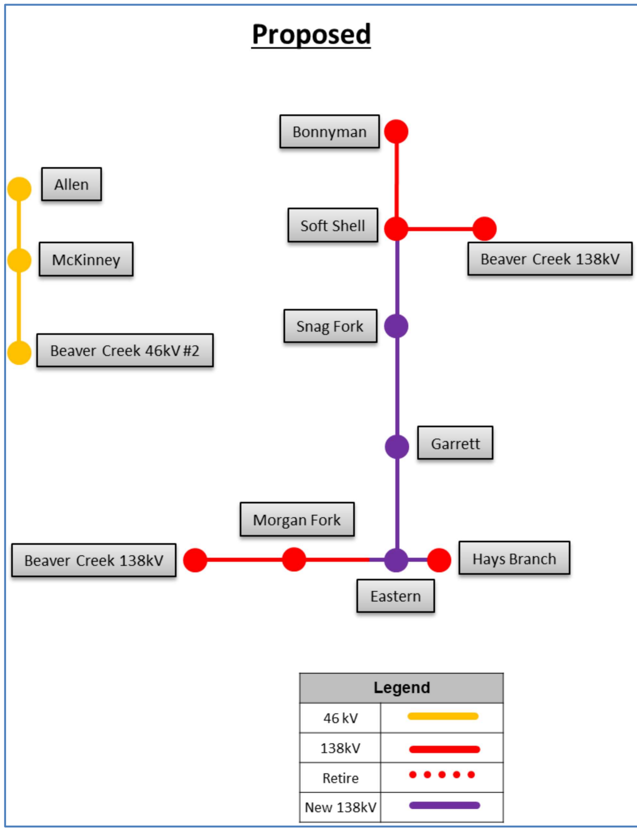
Projected In-Service: ~~10/31/2023~~ 11/15/2024

Supplemental Project ID: S2188.1-.11

Project Status: Scoping

Model: N/A





AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Number: AEP-2020-AP026

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Previously Presented:

Need Meeting 03/19/2020

Solutions Meeting 11/20/2020

Project Driver:

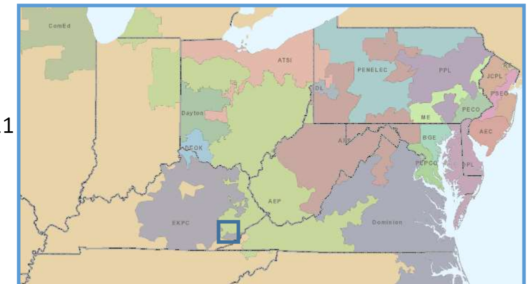
Equipment Condition/Performance/Risk

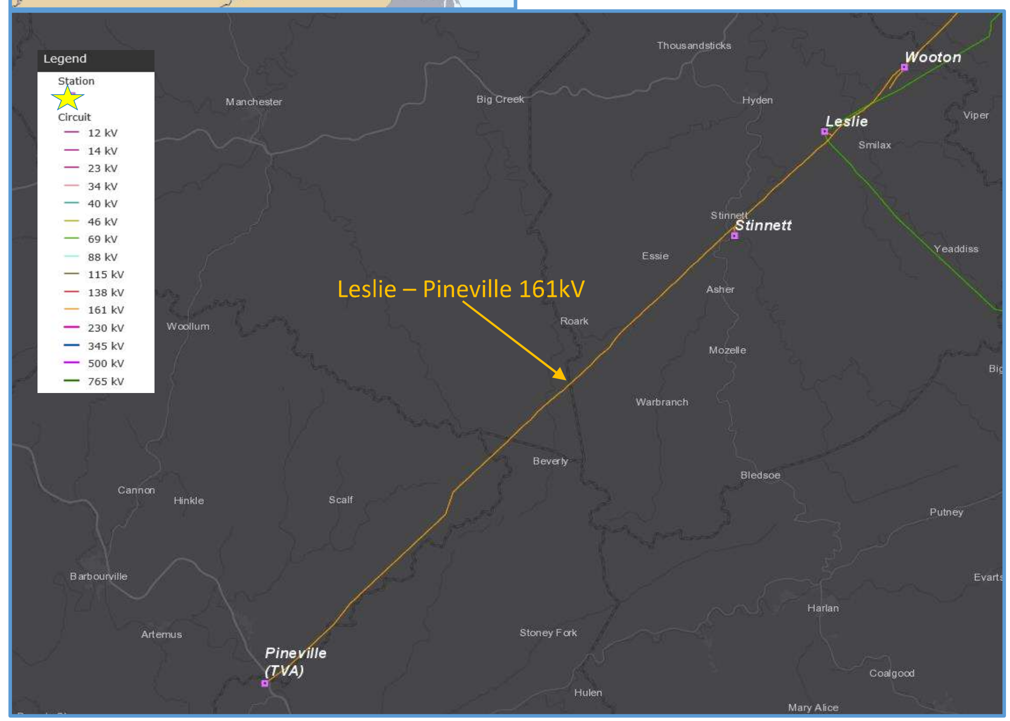
Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
Line Name: Wooton – Pineville 161kV
Line Section: Leslie – Pineville 161kV
Original Install Date (Age): 1942
Length of Line: ~34.24 mi
Total structure count: 189
Original Line Construction Type: Wood
Conductor Type: 500 KCM COPPER
Momentary/Permanent Outages and Duration: 12 Momentary and 5 permanent Outage
CMI (last 5 years only): 26,096 minutes
Line conditions:

Leslie – Pineville line section:

- 130 structures with at least one open condition, 69% of the structures on this circuit.
- 221 structure related open conditions : affecting the crossarm, knee/ vee brace, or pole including rot, split, woodpecker, damaged, loose, and bowed conditions
- 2 open conditions related to the shielding wire, including broken strands
- 3 hardware related open conditions related to insulator, conductor hardware, or shield wire hardware, including broken, missing bolt, and worn





AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Continued:

Line Section: Wooton – Leslie 161kV

Original Install Date (Age): 1942

Length of Line: ~4.68 mi

Total structure count: 23

Original Line Construction Type: Wood

Conductor Type: 500 KCM COPPER

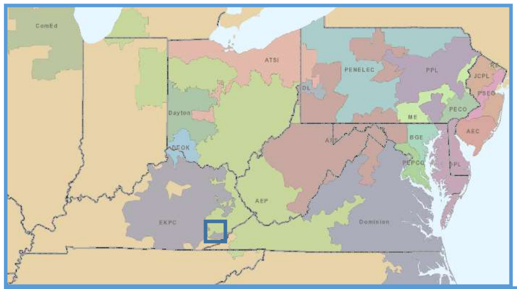
Momentary/Permanent Outages and Duration: none in last five years

CMI (last 5 years only): none in last five years

Line conditions:

Leslie – Wooton line section:

- 17 structures with at least one open condition, 74% of the structures on this section.
- 32 structure related open conditions including: crossarm or pole including rot, insect damage and woodpecker damage



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Number: AEP-2020-AP026

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Selected Solution:

- At Wooton station, upgrade relaying to accommodate new OPGW fiber protection. **Estimated Cost: $1.1 M (s2428.1)**
- At Leslie station, reconductor the 161kV Bus, Relaying upgrades towards Wooton and Pineville, Replace 161kV MOAB W, Replace 161kV XF#1 high side switch. Install DICM. **Estimated Cost: $1.2 M (s2428.2)**
- Remote end work at Hazard substation **Estimated Cost: $0.03 M (s2428.3)**
- Rebuild approximately ~40 miles of Wooton – Pineville 161kV line to address the identified asset condition needs. This work also includes line removal work as well as access road construction. Majority of proposed line rebuild is to be constructed on existing center line. **Estimated Cost: $115.0M (s2428.4)**
- Expand existing ROW for the Wooton – Pineville 161kV line. **Estimated Cost: $8.5 M (s2428.5)**
- Relocate ~0.32 mi 69kV Leslie – Clover Fork which includes of one structure and reconfiguration of the existing line to cross underneath the proposed Wooton-Stinnett 161kV Line. **Estimated Cost: $0.7 M (s2428.6)**
- At Stinnett station, upgrade relaying to accommodate new OPGW fiber protection. Provide transition, entry and termination for OPGW connectivity to the Hazard-Pineville fiber route. **Estimated Cost: $0.7M (s2428.7)**
- Provide transition, entry and termination for OPGW connectivity at Leslie substation. **Estimated Cost: $0.1 M (s2428.8)**

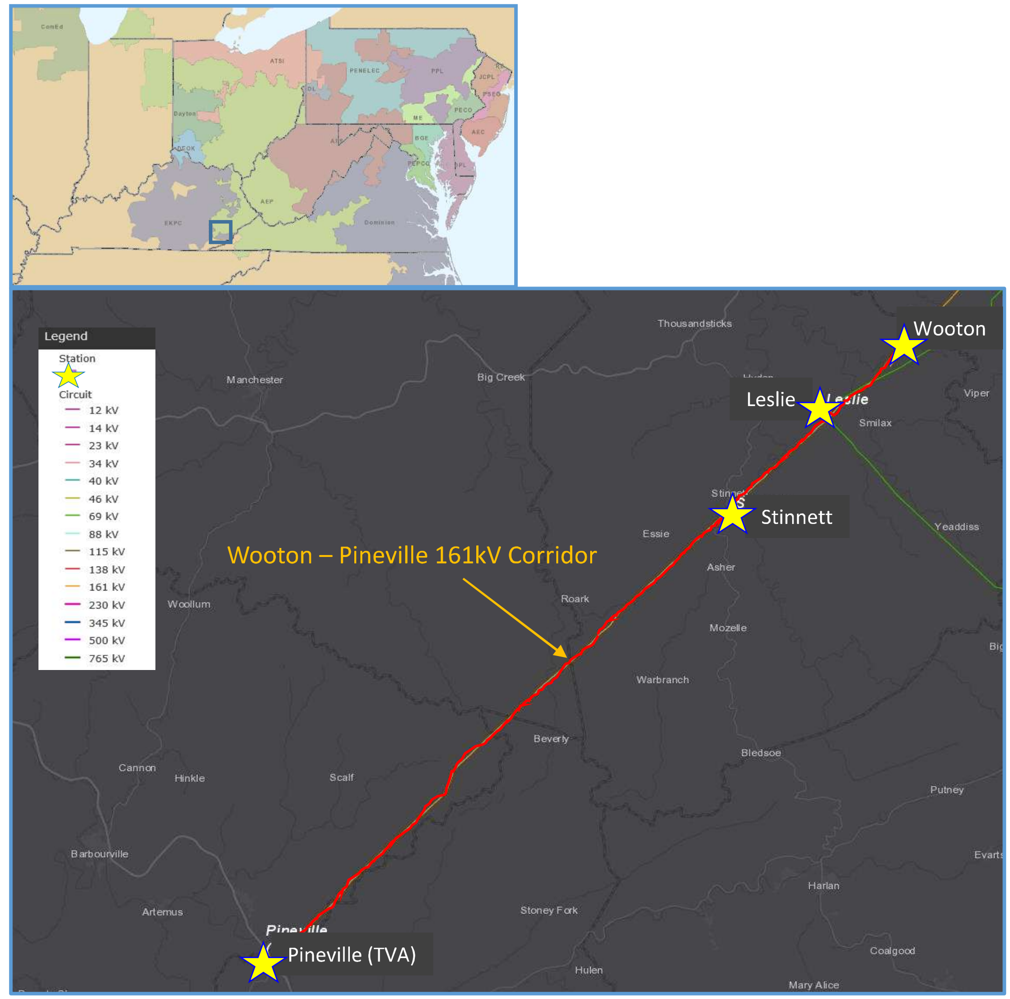
Estimated Cost: $127.33 M

Projected In-Service: 11/31/2027

Supplemental Project ID: s2428.1-.8

Project Status: Scoping

Model: N/A



AEP Transmission Zone: Baseline New Camp - Stone 69kV

Process Stage: Recommended Solution

Criteria: AEP 715 criteria

Assumption Reference: 2025 RTEP assumption

Model Used for Analysis: 2025 RTEP cases

Proposal Window Exclusion: Below 200 kV

Problem Statement:

AEP-VD1160, AEP-VD1161.

In the 2025 Winter RTEP case, voltage drop violations at New Camp 69kV in the event of an N-1-1 scenario that involves the loss 138/69 kV transformer at Johns Creek and loss of Inez - Sprigg 138kV line.

AEP Transmission Zone: Baseline New Camp - Stone 69kV

Recommended Solution:

Construct ~ 2.75 mi Orinoco - Stone 69kV transmission line in the clear between Orinoco station and Stone station. (**B3288.1**) **Estimated Transmission Cost: $9.23 M**

Construct ~ 3.25 mi Orinoco – New Camp 69kV transmission line in the clear between Orinoco station and New Camp station. (**B3288.2**) **Estimated Transmission Cost: $9.95 M**

At Stone substation, Circuit breaker A to remain in place and be utilized as T1 low side breaker, Circuit Breaker B to remain in place and be utilized as new Hatfield (via Orinoco and New Camp) 69KV line breaker. Add new 69KV Circuit Breaker E for Coleman Line exit. (**B3288.3**) **Estimated Transmission Cost: $0.66 M**

Reconfigure the New Camp tap which includes access road improvements/installation, temporary wire and permanent wire work along with dead end structures installation. (**B3288.4**) **Estimated Transmission Cost: $0.45 M**

At New Camp substation, rebuild the 69kV bus, add 69KV MOAB W and replace the 69KV Ground switch Z1 with a 69kV Circuit Switcher on the New Camp Transformer. (**B3288.5**) **Estimated Transmission Cost: $1.18 M**

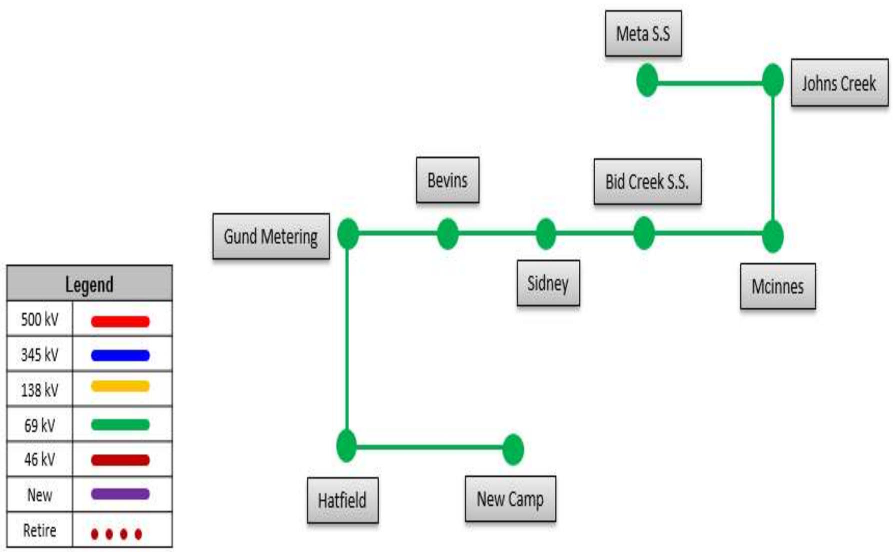
Total estimated baseline Cost: $21.47 M

Preliminary Facility Rating:

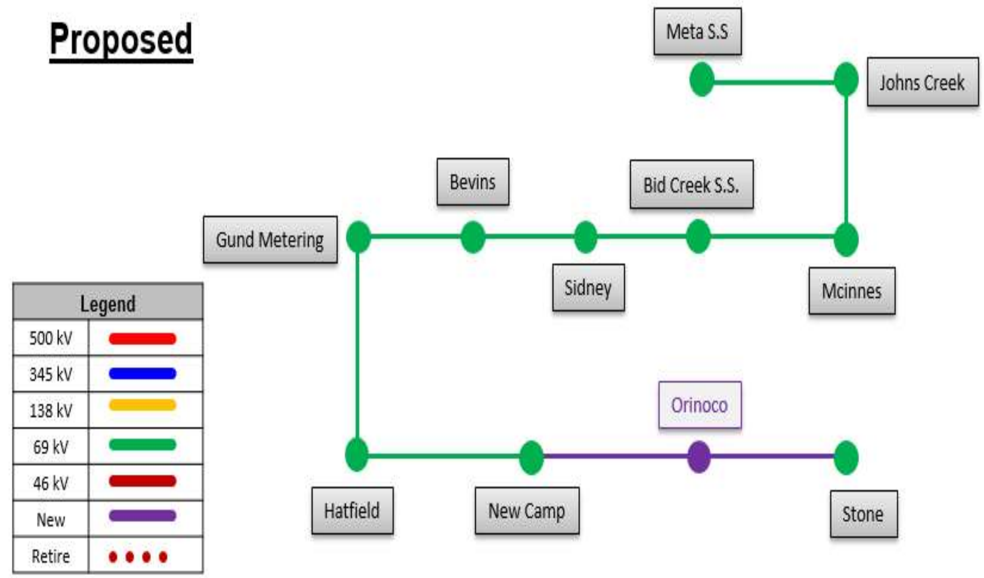
Branch	SN/SE/WN/WE (MVA)
05ORINOCO – 05STONE 69KV	102/142/129/160
05ORINOCO – 05NEWCAMP 69KV	102/142/129/150

AEP Transmission Zone: Baseline New Camp - Stone 69kV

Existing



Proposed



Ancillary Benefits:

This work addresses the needs identified in AEP-2020-AP028. Removal of obsolete ~8.23 mi of 46kV transmission line, Looped service to New Camp station which is served via a radial ~4.14 mile, 69 kV line from Hatfield Station and serves approximately 14.6 MVA of peak load..

Required In-Service: 12/1/2025

Projected In-Service: 12/1/2025

Previously Presented: 12/18/2020

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process New Camp

Need Number: AEP-2020-AP028

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

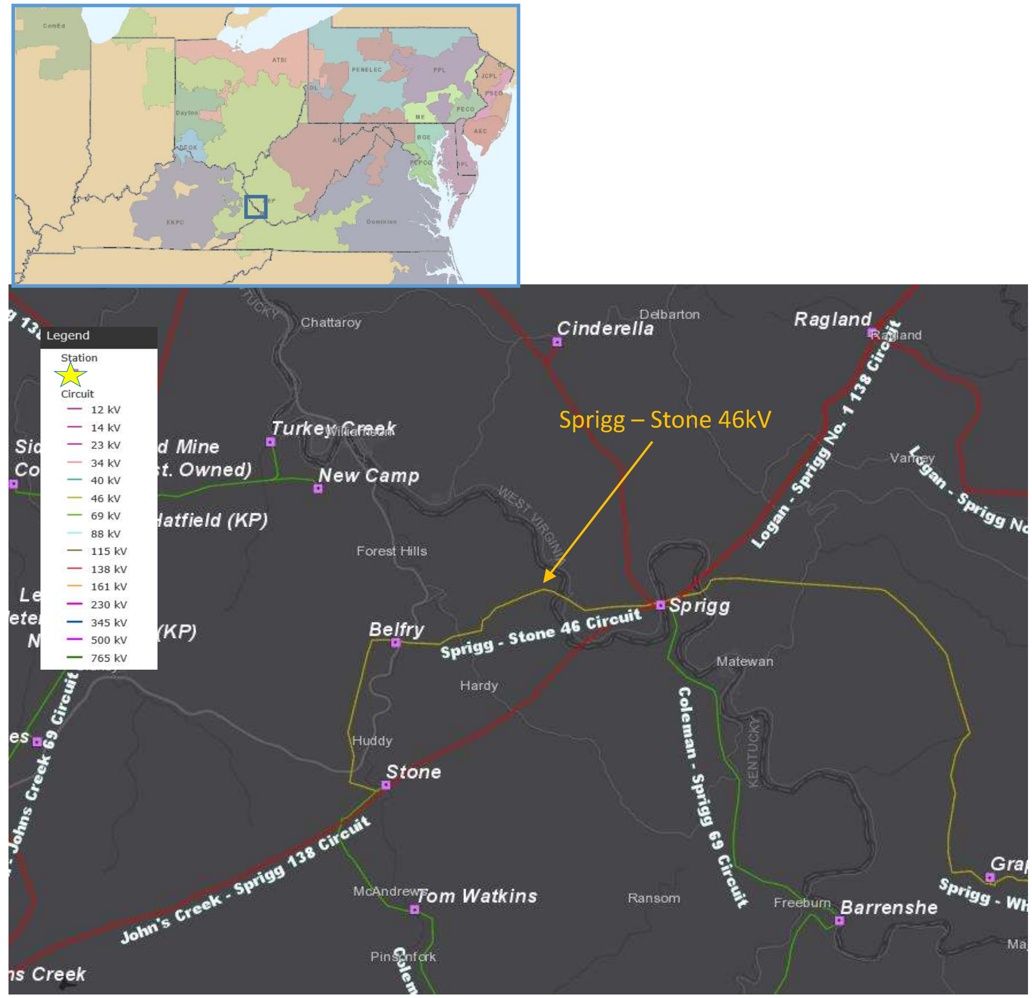
Previously Presented:
Need Meeting 04/20/2020
Solution Meeting 01/15/2021

Project Driver:
Equipment Condition/Performance/Risk

Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 13)

Problem Statement:
Line Name: Sprigg – Stone 46kV
Original Install Date (Age): 1940
Length of Line: 8.23 mi
Total structure count: 55
Original Line Construction Type: Wood
Majority Conductor Type: 3/0 ACSR 6/1 (Pigeon) and 2/0 COPPER
Momentary/Permanent Outages and Duration: 6 Momentary and 7 permanent Outage
CMI (last 5 years only): 1,119,129 minutes
Line conditions:

- 35 structures with at least one open condition, 64% of the structures on this circuit.
- 98 structure related conditions: rotted poles, crossarms and braces, woodpecker damage, bowed braces and loose braces, affecting the crossarm, knee/ vee brace, or pole including rot, split, woodpecker, damaged, loose, and bowed conditions
- 1 open conditions related to the broken strands on a jumper conductor
- 9 hardware related open conditions loose or broken guy wires



AEP Transmission Zone M-3 Process
New Camp

Need Number: AEP-2020-AP028

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Selected Solution:

In conjunction with the baseline work identified under B3288 presented in 12/18/2020 SRRTEP – West meeting which would install new 69kV line between Stone and New Camp via Orinoco substation, the following is proposed under this solution to address the identified needs on the Sprigg – Stone 46kV line.

Replace Belfry substation with Orinoco substation by installing a 69KV box bay and 12KV rural bay to be built in the clear southwest of existing Belfry station. Install 69/12kV 20 MVA transformer and two 12kV breakers. **Estimated Transmission Cost: $0.65 M (s2446.1)**

Retire Belfry 46kV substation. **Estimated Transmission Cost: $0 M (s2446.2)**

Retire 46kV equipment from Stone substation. **Estimated Transmission Cost: $0.07 M (s2446.3)**

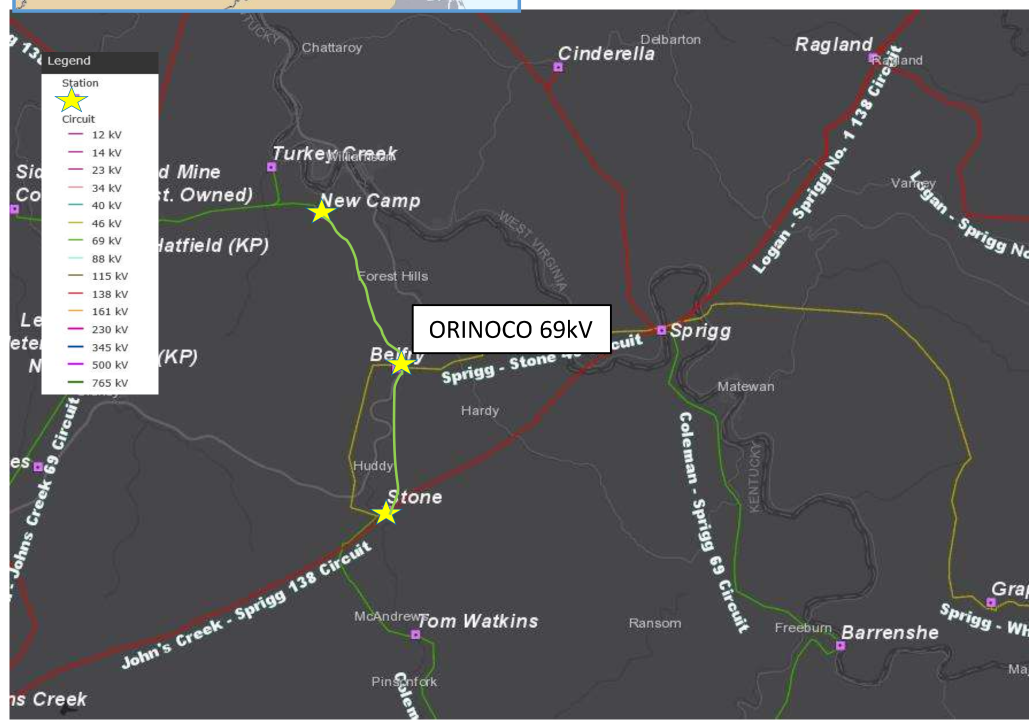
At Hatfield substation, replace MOAB Y with a 69KV Circuit Breaker towards Stone 69kV line via New Camp and Orinoco. **Estimated Transmission Cost: $0.85 M (s2446.4)**

Retire the 46kV equipment at Sprigg station towards Stone (via Belfry). **Estimated Transmission Cost: $0.05 M (s2446.5)**

Retire Turkey Creek Tap. **Estimated Transmission Cost: $0.76 M (s2446.6)**

Retire the ~8.23 miles of the 46kV Sprigg – Stone 46 KV circuit. **Estimated Transmission Cost: $6.73 M (s2446.7)**

Total Estimated Transmission Cost: $9.11 M



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
New Camp

Need Number: AEP-2020-AP028

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Ancillary Benefits: Removal of obsolete ~8.23 mi of 46kV transmission line and associated equipment

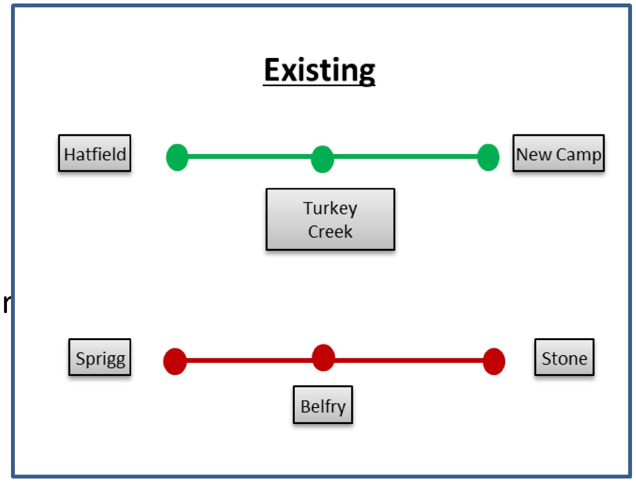
Required In Service Date: 9/1/2025

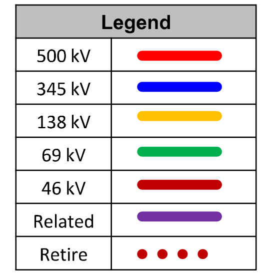
Projected In Service Date: 12/31/2024

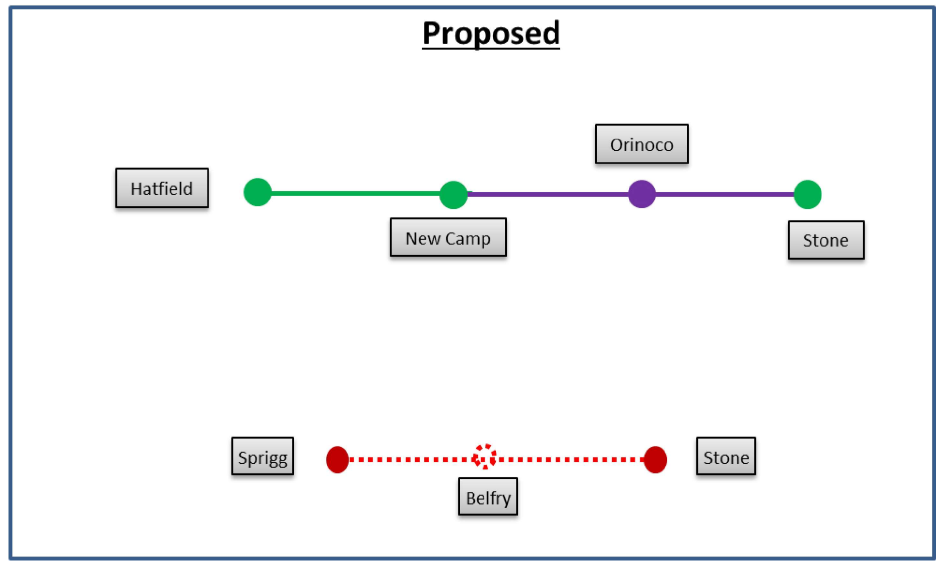
Supplemental Project ID: s2446.1-.7

Project Status: Scoping

Model: N/A







AEP Transmission Zone: Baseline Prestonsburg - Thelma 46kV Rebuild

Process Stage: Recommended Solution

Criteria: AEP 715 Criteria

Assumption Reference: 2026 RTEP assumption

Model Used for Analysis: 2026 RTEP cases

Proposal Window Exclusion: Below 200 kV Exclusion

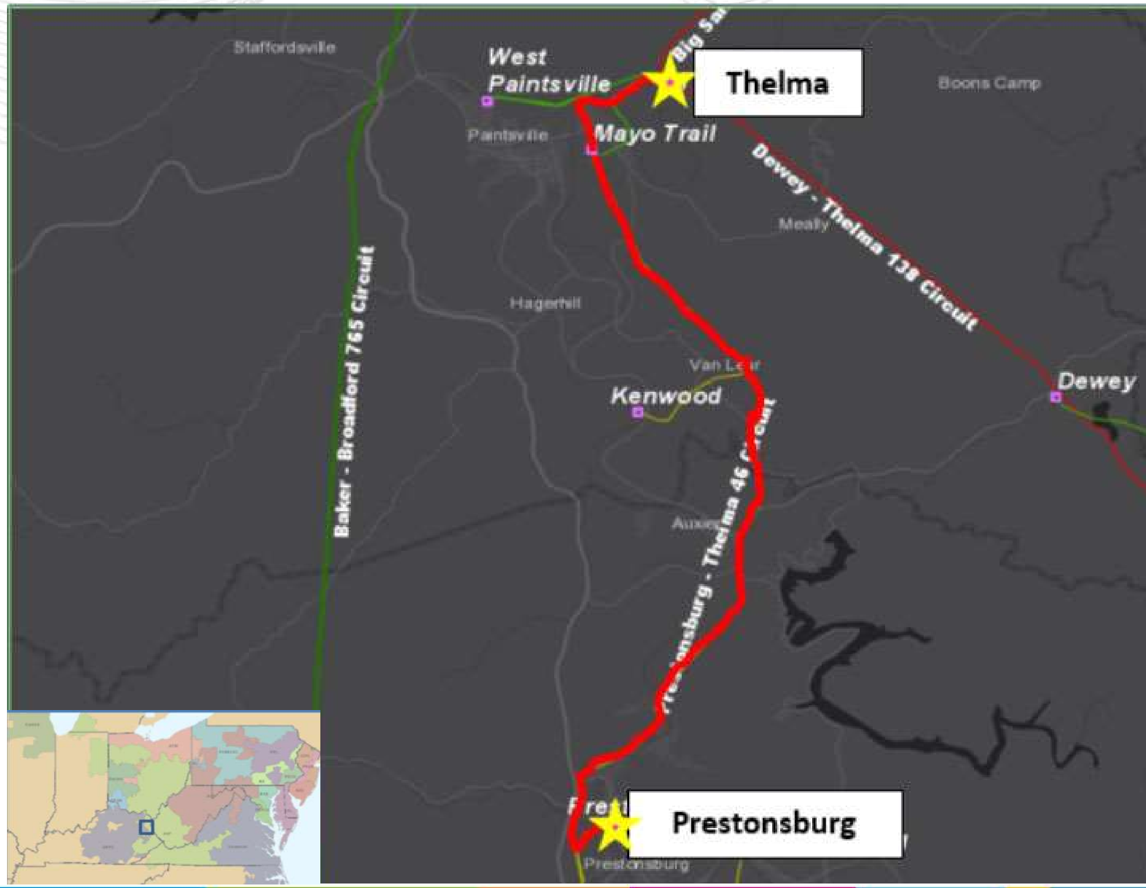
Problem Statement:

FG: AEP-VM10, AEP-VM11, AEP-VM12, AEP-VM13, AEP-VM14, AEP-VM15, AEP-VM16, AEP-VM17, AEP-VM18, AEP-VM19, AEP-VM20, AEP-VM21, AEP-VM22, AEP-VM23, AEP-VM24, AEP-VM25, AEP-VM26, AEP-VM27, AEP-VM28, AEP-VM29, AEP-VM30, AEP-VM31, AEP-VM32, AEP-VM33, AEP-VM34, AEP-VM35, AEP-VM36, AEP-VM37, AEP-VM38, AEP-VM39, AEP-VM40, AEP-VM41, AEP-VD15, AEP-VD16, AEP-VD17, AEP-VD18, AEP-VD19, AEP-VD20, AEP-VD21, AEP-VD22, AEP-VD23, AEP-VD24, AEP-VD25, AEP-VD26, AEP-VD27, AEP-VD28, AEP-VD29, AEP-VD30, AEP-VD31, AEP-VD32, AEP-VD33, AEP-VD34, AEP-VD35, AEP-VD36, AEP-VD37, AEP-VD38, AEP-VD39, AEP-VD40, AEP-VD41, AEP-VD42, AEP-VD43, AEP-VD44, AEP-VD45, AEP-VD46

In 2026 RTEP Winter case, voltage magnitude and voltage drop violations at Mckinney, Salsbury, Allen, East Prestonsburg, Prestonsburg, Middle Creek, Kenwood 46kV buses are identified for multiple N-1-1 contingency pairs.

Existing Facility Rating:

Branch	SN/SE/WN/WE (MVA)
05Thelma – 05KENWDTAP 46KV	50/50/63/63



AEP Transmission Zone: Baseline Prestonsburg - Thelma 46kV Rebuild

Recommended Solution:

Rebuild Prestonsburg - Thelma 46kV circuit, approximately 14 miles. Retire Jenny Wiley SS. (**B3361**)

Transmission Estimated Cost: $33.01M

Preliminary Facility Rating:

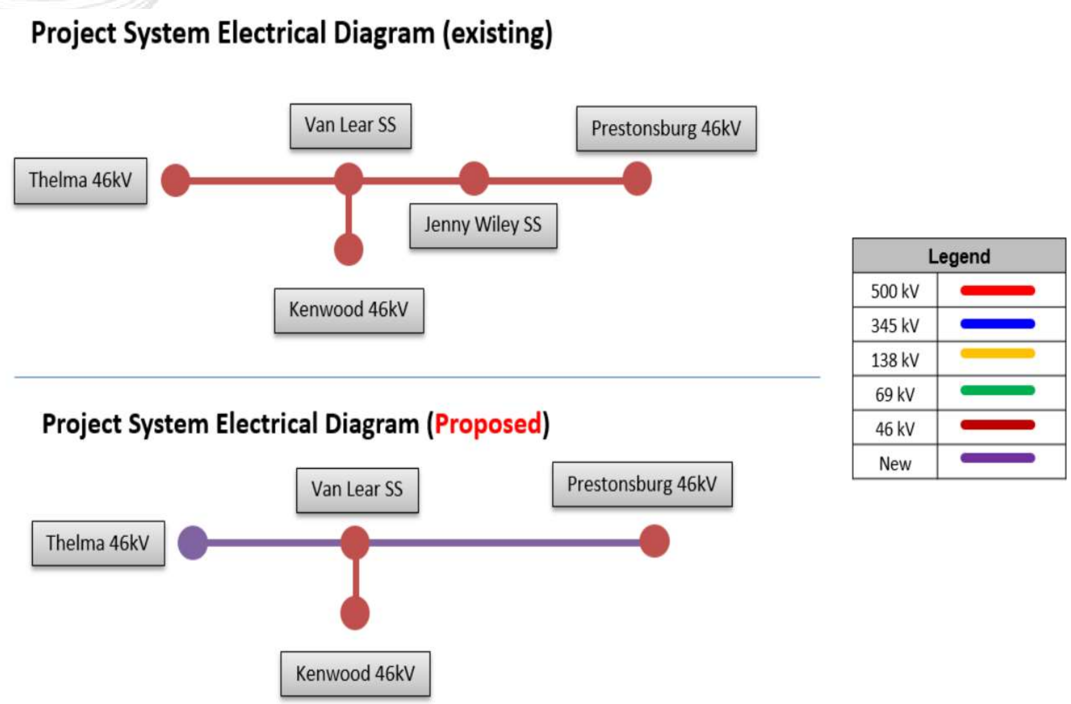
Branch	SN/SE/WN/WE (MVA)
05Thelma – 05KENWDTAP 46KV	68/85/86/101
05PRESTNSB– 05KENWDTAP 46KV	68/85/86/101

Ancillary Benefits: The proposed solution also completely addresses the identified needs in AEP-2018-AP022.

Required IS date: 12/1/2026

Projected IS date: 10/1/2025

Previously Presented: 10/15/2021



AEP Transmission Zone: Baseline Thelma Transformer Replacement

Process Stage: Recommended Solution

Criteria: AEP 715 Criteria

Assumption Reference: 2026 RTEP assumption

Model Used for Analysis: 2026 RTEP cases

Proposal Window Exclusion: Below 200 kV Exclusion

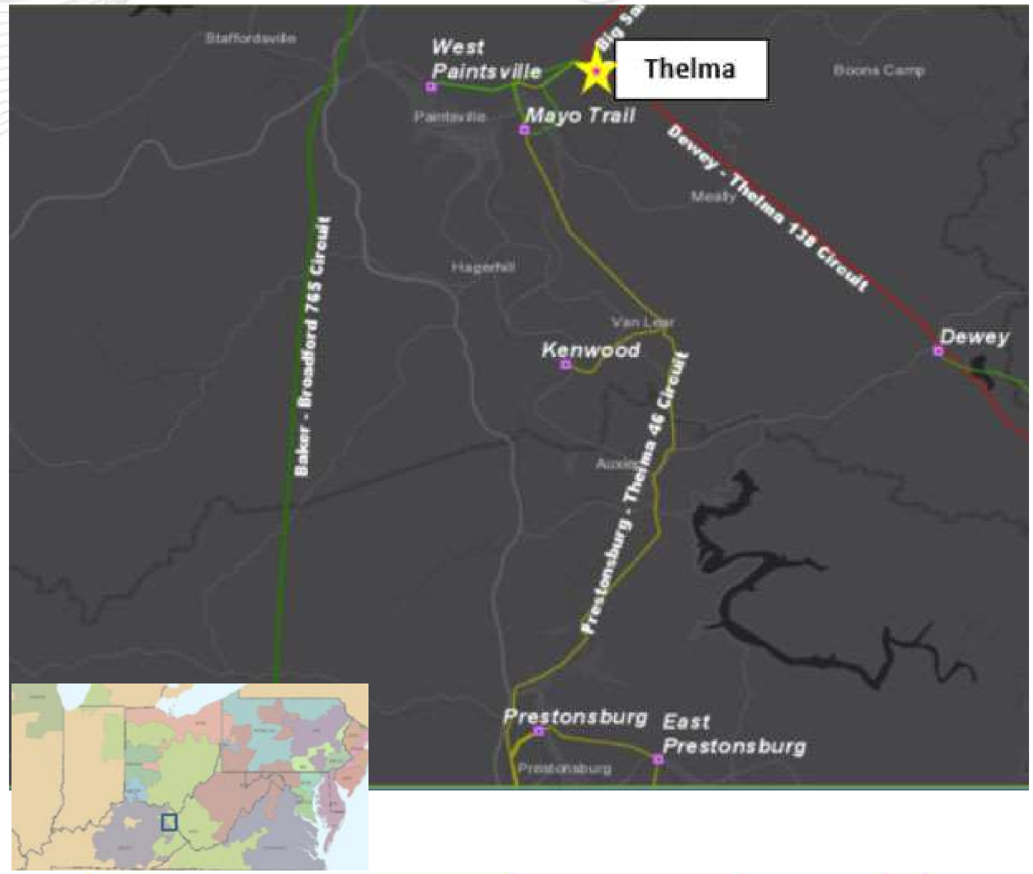
Problem Statement:

FG: AEP-T70, AEP-T71, AEP-T72

In 2026 RTEP Winter case, the 46kV winding of the Thelma TR#1 is overload for multiple N-1-1 contingency pairs.

Existing Facility Rating:

Branch	SN/SE/WN/WE (MVA)
05THELMAEQ – 05THELMA 999/138KV	84/92/84/92
05THELMAEQ – 05THELM1 999/69KV	84/92/84/92
05THELMAEQ – 05THELMA 999/46KV	53/58/53/58



AEP Transmission Zone: Baseline Thelma Transformer Replacement

Recommended Solution:

Replace Thelma Transformer #1 with a 138/69/46kV 130/130/90 MVA transformer and replace 46kV risers and relaying towards Kenwood substation. Existing TR#1 to be used as spare. (**B3360**)

Transmission Estimated Cost: $3.54M

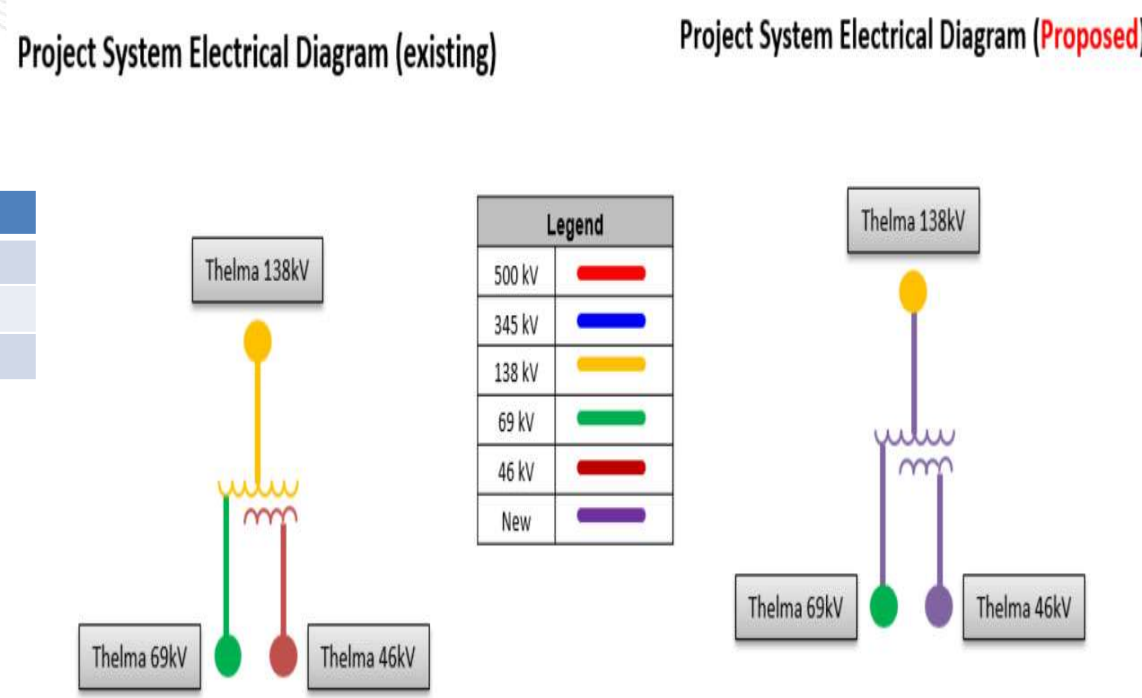
Preliminary Facility Rating:

Branch	SN/SE/WN/WE (MVA)
05THELMAEQ – 05THELMA 999/138KV	130/130/130/130
05THELMAEQ – 05THELM1 999/69KV	130/130/130/130
05THELMAEQ – 05THELMA 999/46KV	90/90/90/90

Required IS date: 12/1/2026

Projected IS date: 10/1/2025

Previously Presented: 10/15/2021



AEP Transmission Zone M-3 Process
Johnson County, KY

Need Number: AEP-2020-AP029

Process Stage: Solutions Meeting 03/19/2021

Previously Presented: Needs Meeting 04/20/2020

Supplemental Project Driver: Equipment Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Line Name: Kenwood – Van Lear 46kV

Original Install Date (Age): 1969

Length of Line: 1.77 mi

Total structure count: 11

Original Line Construction Type: Wood

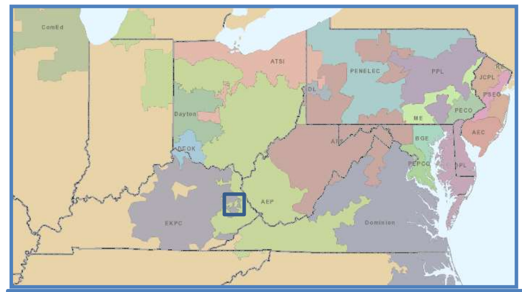
Conductor Type: 336,400 ACSR 26/7

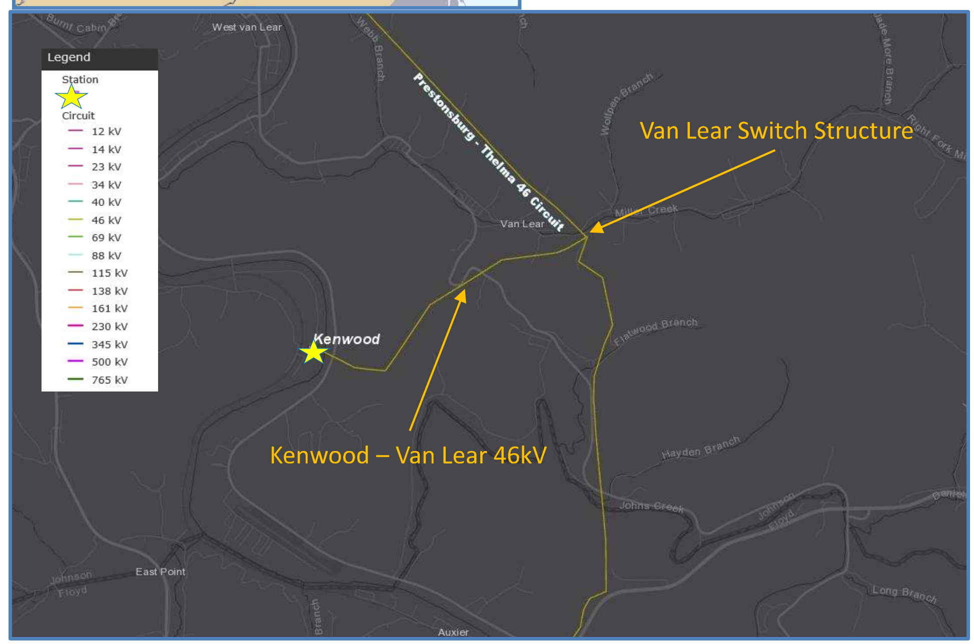
Line conditions:

- 3 of the 11 structures have conditions that comprise 27% of the line section.
- Open conditions include: rot and woodpecker damage.
- Kenwood Station is currently radially fed with a peak load near 22 MVA.

Van Lear Switch:

- The switches at Van Lear have been tagged as inoperable and unsafe to operate. The old hydraulic type mechanism on these switches does not operate properly, arcing horns are burnt off, and operating rod supports are damaged.





AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

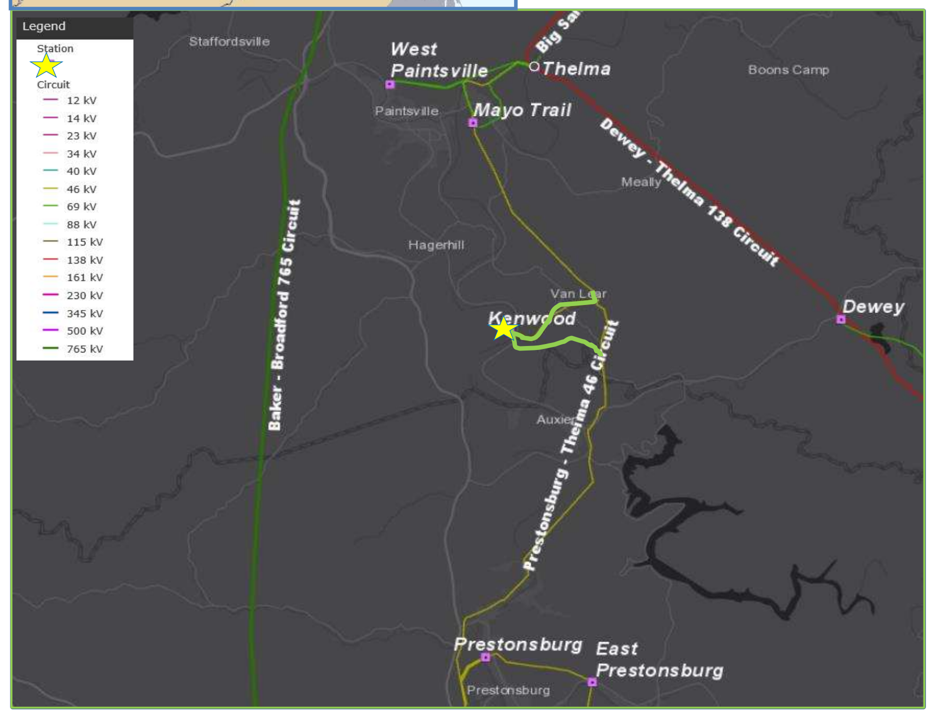
AEP Transmission Zone M-3 Process
Johnson County, Kentucky

Need Number: AEP-2020-AP029

Process Stage: Solutions Meeting 03/19/2021

Proposed Solution:

- A green field line is to be constructed (Kenwood 69kV Extension) and to be operated at 46kV. The new extension will provide looped service into Kenwood substation. It will be approximately 2.25 miles of single circuit construction through mountainous terrain in Floyd and Johnson Counties in Kentucky. The extension will tap the existing Prestonsburg-Thelma 46kV Line around structure K346-50. (SN:53 MVA , SE:61 MVA, WN:67 MVA, WE:73 MVA) **Estimated Cost: $5.8 M**
- Rebuild the existing ~1.77 mi Kenwood Tap line from Kenwood to Van Lear Tap Structure on the existing center line. (SN:53 MVA , SE:61 MVA, WN:67 MVA, WE:73 MVA)
  Estimated Cost: $4.9 M
- Provide splicing for 2.25 miles of 96ct OPGW on the Kenwood 69kV Extension Line and 1.77 mi Kenwood TAP line. This extension spans from Kenwood Station to the Prestonsburg-Thelma 46kV line. **Estimated Cost: $0.1 M**
- At Kenwood substation, Extend the walk bus and add second 46KV line to set up Kenwood station as a looped station with MOABS protecting each exit. Add new H-Frame dead end with MOAB and single phase CCVT. Add MOAB and single phase CCVT to existing line. Relocate 3 phase CCVT's from cap bank AA to 46KV Bus. Add 3-bay transclosure, and separate battery enclosure. Replace Battery and Charger. **Estimated Cost: $0 M (Distribution costs only)**
- Retire Van Lear SS. **Estimated Cost: $0.1 M**
- Remote end work at Prestonsburg substation. **Estimated Cost: $0 M (Distribution costs only)**
- Retire the ~1.5 mi 46kV line section from str. 52 to Van Lear SS. This line section is part of the Prestonsburg – Thelma 46kV line need (AEP-2018-022). **Estimated Cost: $1.2 M**



AEP Transmission Zone M-3 Process
Floyd/Johnson County, Kentucky

Proposed Solution (Cont.):

Ancillary benefits:
- Removal of ~1.5 mi 46kV line section on Prestonsburg – Thelma 46kV line mitigates issues identified on this line section, solutions are currently being evaluated to address the remainder of the needs on the entire Prestonsburg – Thelma line (AEP-2018-022).
- Proposed work would also improve reliability for customers served from Kenwood substation. Kenwood substation serves 22 MVA of load at peak and only half of that load is transferrable.

Total Estimated Transmission Cost: $12.1 M

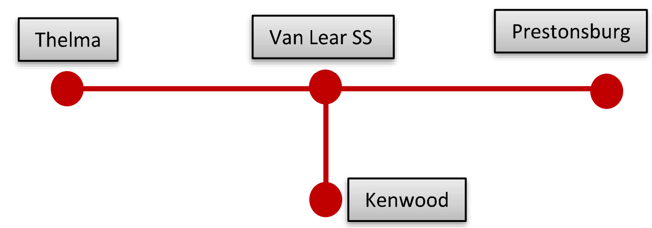
Alternative considered:

Alternative:
- Relocate and replace the Van Lear switch. It would need to be relocated from its current position in order to be replaced and facilitate accessibility. Install new ~2.25 mi 69kV Kenwood Tap line (energized at 46kV) section from Prestonsburg – Thelma 46kV line. Rebuild 1.5 miles of line on Prestonsburg-Thelma to address portion of need identified under AEP-2018-AP022 instead of retiring this section as proposed. Retire ~1.77 mi existing 46kV line from Kenwood to the existing Van Lear switch. After this work is complete, Kenwood would still be radially fed and in an area where outages could potentially be extensive due to the nature of local terrain.
- **Estimated Alternative Cost: $14.5 M**

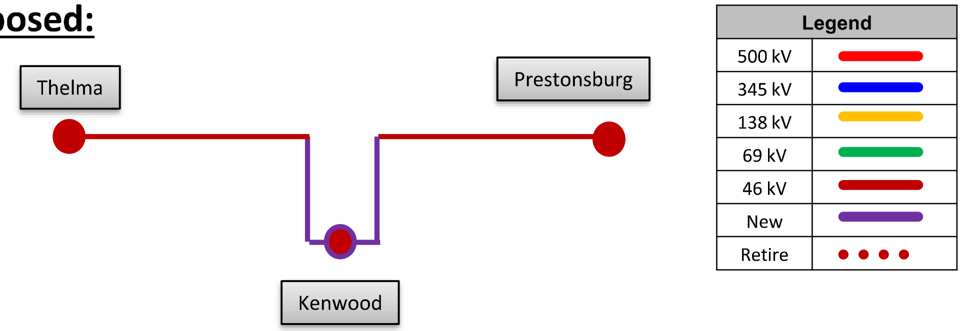
Projected In-Service: 11/30/2023

Project Status: Scoping

Existing:



Proposed:



AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

Process Stage: First Review Solution

Criteria: AEP 715 Criteria

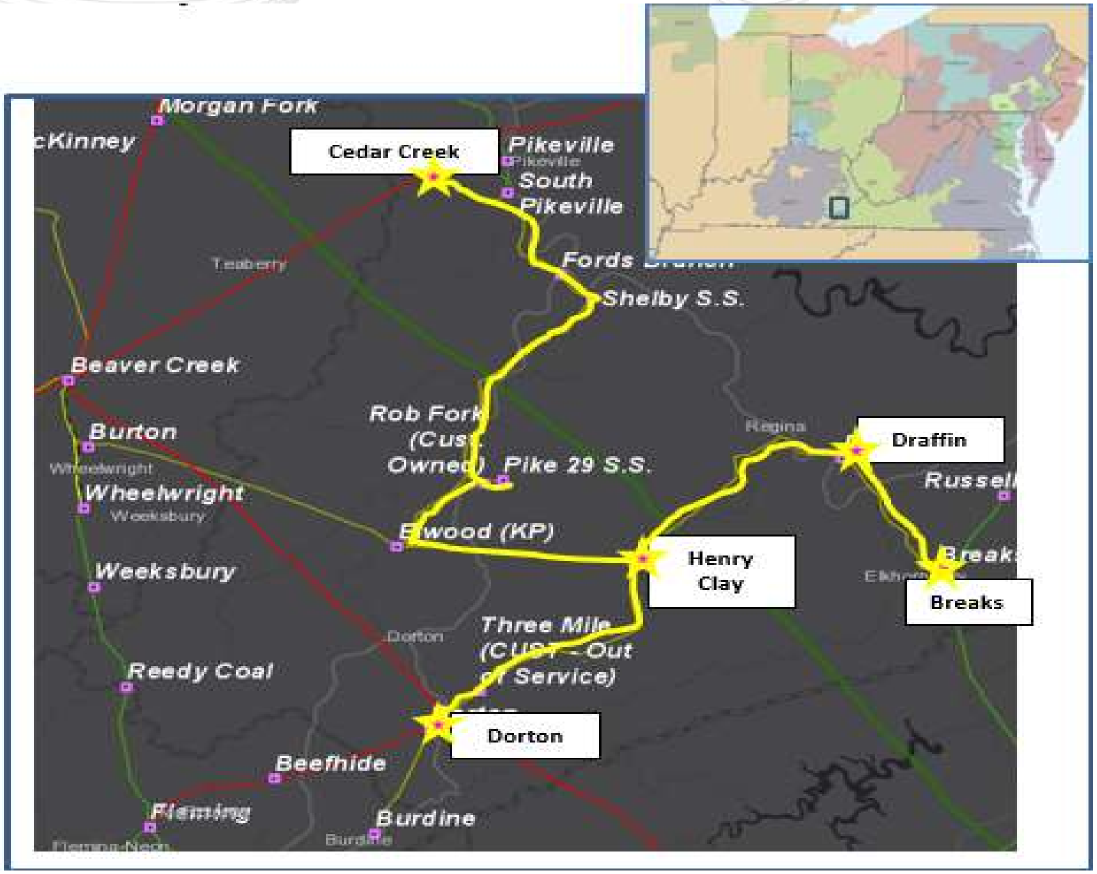
Assumption Reference: 2027 RTEP assumption

Model Used for Analysis: 2027 RTEP Winter case

Proposal Window Exclusion: Below 200 kV Exclusion

Problem Statement: 2022W1-AEP-VM4 through 2022W1-AEP-VM21, 2022W1-AEP-VD5 through 2022W1-AEP-VD24

In 2027 Winter RTEP case, Dorton, Pike 29, Rob Fork, Burdine, Henry Clay, Draffin 46KV buses (along the Cedar Creek - Elwood and Breaks - Dorton – Elwood 46KV circuits) experience voltage magnitude and drop violations under multiple N-1-1 contingency scenarios.



AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

Proposed Solution:

Transmission Components:

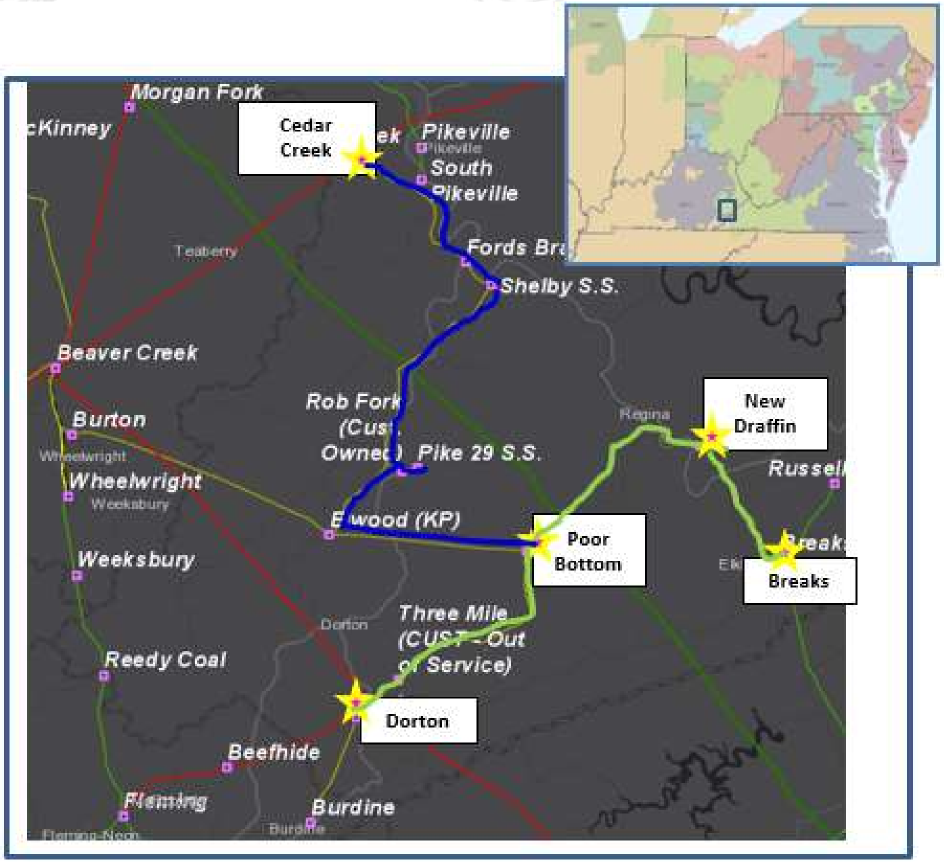
- Establish 69kV bus and new 69 kV line CB at Dorton substation. $1.13 M
- At Breaks substation, reuse 72kV breaker A as the new 69kV line breaker. $0.71 M
- Rebuild ~16.7 mi Dorton – Breaks 46kV line to 69kV. $58.52
- Retire ~17.2 mi Cedar Creek – Elwood 46kV circuit. $11.15 M
- Retire ~ 6.2 mi Henry Clay – Elwood 46kV line section. $4.3 M
- Retire Henry Clay 46 kV substation and replace with Poor Bottom 69 kV station. Install a new 0.7 mi double circuit extension to Poor Bottom 69kV. $3.42 M
- Retire Draffin substation and replace with a new substation. Install a new 0.25 mi double circuit extension to New Draffin substation. $2.01M
- Remote End work at Jenkins substation. $0.03 M
- Provide Transition fiber to Dorton, Breaks, Poor Bottom, Jenkins and New Draffin substations. $0.41M
- Henry Clay S.S Retirement: $ 0.3 M
- Cedar Creek substation work: $0.44 M
- Breaks substation retire 46kV equipment: $0.25 M
- Retire Pike 29 SS and Rob Fork SS: $0.42 M

Total Transmission Estimated Cost: $83M

Distribution Components:

- Serve Pike 29 and Rob Fork customers from nearby 34kV Distribution sources. $ 2.23 M (D cost)
- Poor Bottom substation install: $8.46 M (D cost)
- Henry Clay 46kV substation retirement: $0.82 M (D cost)
- New Draffin 69kV substation install: $6.66 M (D cost)
- Draffin 46kV substation retirement: $0.68 M (D cost)

Total Distribution Estimated Cost: $18.9M



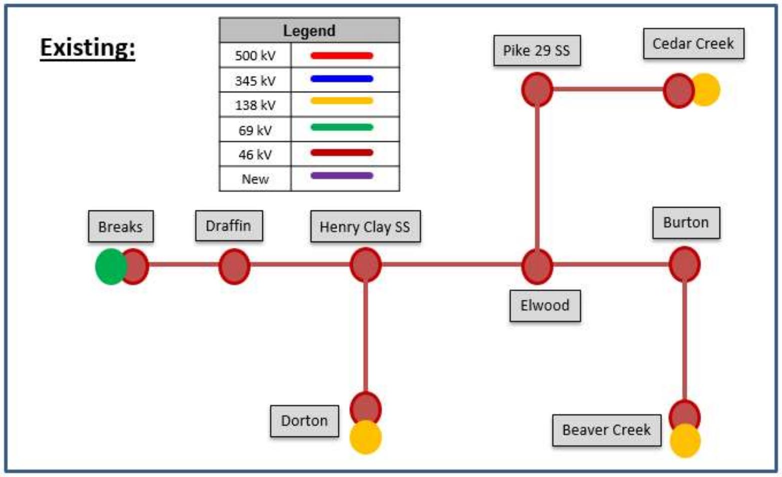
AEP Transmission Zone: Baseline Breaks - Dorton 69kV Conversion

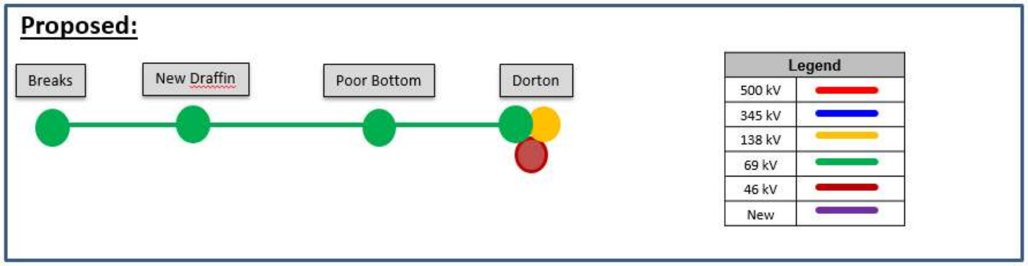
Alternatives: Install 9.6 MVAR 46kV Cap Bank at Dorton substation. This cap bank must be served off the 46kV Bus. Also, install 12.9 MVAR Cap Bank at Cedar Creek substation 46kV Bus. While this fixes the baseline issues identified, it does not address the supplemental needs as identified and mitigated with the proposed solution. (Estimated Cost: $2.58 M)

Ancillary Benefits: This proposal completely addresses identified supplemental needs on Cedar Creek – Elwood 46kV under Need AEP-2019-AP032 (presented 8/29/2019 W-SRRTEP), and Identified supplemental needs on Breaks – Dorton – Elwood 46kV circuit under AEP-2020-AP012 (presented 2/21/2020 W-SRRTEP). The proposal proposes retirement of roughly 23.4 mi of obsolete 46kV line.

Required in-service date: 12/1/2027

Projected in-service date: 7/31/2027





AEP Transmission Zone M-3 Process
Beaver Creek – Elwood 46kV

Need Number: AEP-2020-AP009

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Previously Presented:
Needs Meeting 02/21/2020
Solutions Meeting 11/20/2020

Project Driver:
Equipment Condition/Performance/Risk, Operational Flexibility

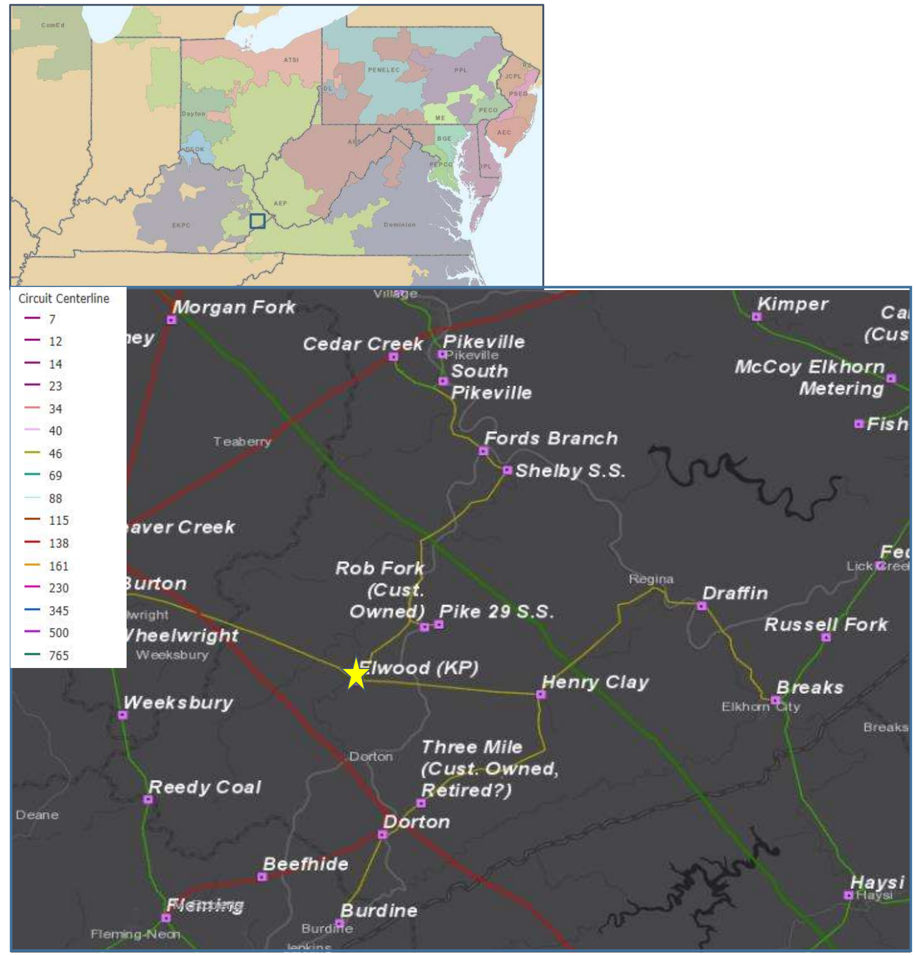
Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Elwood 46kV Station:

46 kV Circuit Breakers A,B, and C

- 1960's vintage FZO-69-1500P type oil circuit breakers.
- Fault Ops: CB A (33), CB B (83), and CB C (105). Recommended : 10
- Other drivers: damage to bushings, spare part availability, historical reliability, and lack of vendor support of the breakers.
- There are 8 remaining FZO-69-1500P circuit breakers on the AEP system, including the 3 at this station.
- 86% of the relays (36/42) at the station are electromechanical, which have significant limitations with regards to fault data collection and retention and have no spare part availability due to a lack vendor support.



AEP Transmission Zone M-3 Process
Beaver Creek – Elwood 46kV

Need Number: AEP–2020-AP011

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Previously Presented:

Needs Meeting 02/21/2020

Solutions Meeting 11/20/2020

Project Driver:

Equipment Material/ Condition/Performance/Risk, Operational Flexibility and Efficiency

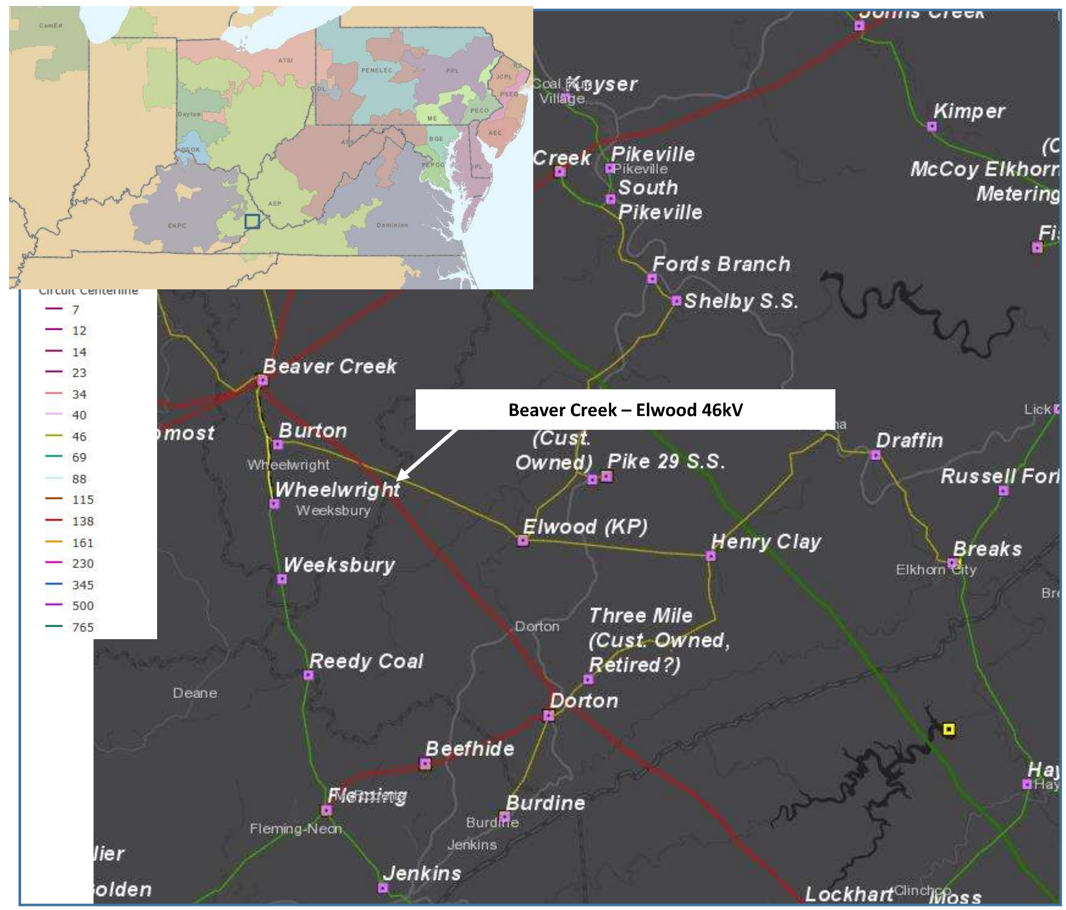
Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

Beaver Creek – Elwood 46kV:

- Original Install Date: 1930s vintage
- Length of Line: ~10.48 mi
- Total structure count: 60
- Original Line Construction Type: Wood
- Conductor Type: 336 ACSR
- Momentary/Permanent Outages and Duration: 18 Momentary and 1 permanent Outage
- CMI (last 5 years only): 269,070 minutes
- Number of open conditions: 34 open conditions on 20 unique structures.
- Open conditions include crossarms and poles with rot top, woodpecker damage and leaning-in-line conditions.



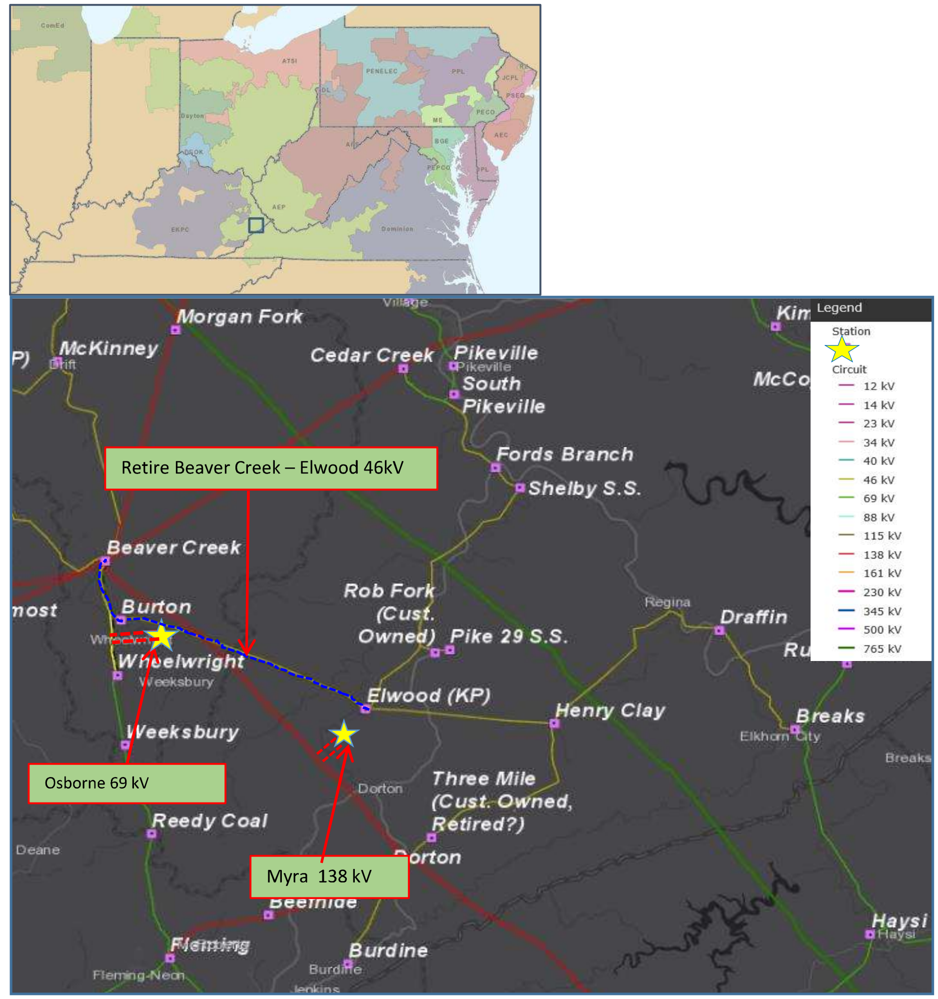
AEP Transmission Zone M-3 Process
Beaver Creek – Elwood 46kV

Need Number: AEP-2020-AP009, AEP–2020-AP011

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Selected Solution:

- Construct a greenfield 69/12 KV Osborne Station to replace Burton Station, including a high-side 69KV Phase Over Phase switch, fiber connectivity, a circuit switcher, and one 69/12kV 12/16/20MVA transformer and associated distribution feeders. **Estimated Transmission Cost: $0.74M (s2436.1)**
    - Note: Cost does not include the Distribution scope of work.
- Construct a greenfield 138KV Myra Station to replace Elwood Station. Install 138KV double box bay with two 138kV circuit breakers and line exits to Fremont & Beaver Creek. Install 138/34.5 kV transformer with high-side circuit switcher and associated 34.5kV breakers. Install fiber connectivity for upgraded relaying. **Estimated Transmission Cost: $3.43 M (s2436.2)**
    - Note: Cost does not include the Distribution scope of work.
- Remote end relaying work at Beaver Creek substation. Remove 46KV Elwood Line 46kV circuit breaker "G" and associated equipment. **Estimated Transmission Cost: $0.17 M (s2436.3)**
- Remote end relaying work at Fremont substation. **Estimated Transmission Cost: $0.42 M (s2436.4)**
- At Burton station, retire and remove all existing equipment. **Estimated Transmission Cost: $0M (s2436.5)**
- At Elwood station, retire and remove all existing equipment. **Estimated Transmission Cost: $0 M (s2436.6)**
- Construct a new ~0.5 mi double circuit 69 kV line to the proposed Osborne substation. **Estimated Cost: $2.56 M (s2436.7)**
- Reconfigure the existing Beaver Creek - Fleming 69kV line to facilitate the construction of the new double circuit Osborne 69kV line to feed the proposed Osborne Substation. **Estimated Cost: $1.22 M (s2436.8)**



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Beaver Creek – Elwood 46kV

Proposed Solution (Cont.):

- Construct a new ~2 mi double circuit 138 kV line to the proposed Myra substation. **Estimated Cost: $8.8 M (s2436.9)**
- Reconfigure the existing Beaver Creek - Fremont 138kV circuit to facilitate the construction of the new double circuit Myra Extension 138kV Line to feed the proposed Myra Substation. **Estimated Cost: $1 M (s2436.10)**
- Install two replacement structures in order to bypass Elwood station. Transfer wires from old structure to new structure. Tie new structure to Cedar Creek-Henry Clay 46kV Line. **Estimated Cost: $1.35 M (s2436.11)**
- Retire ~10.48 mi Beaver Creek – Elwood 46kV line. **Estimated Cost: $6.47 M (s2436.12)**

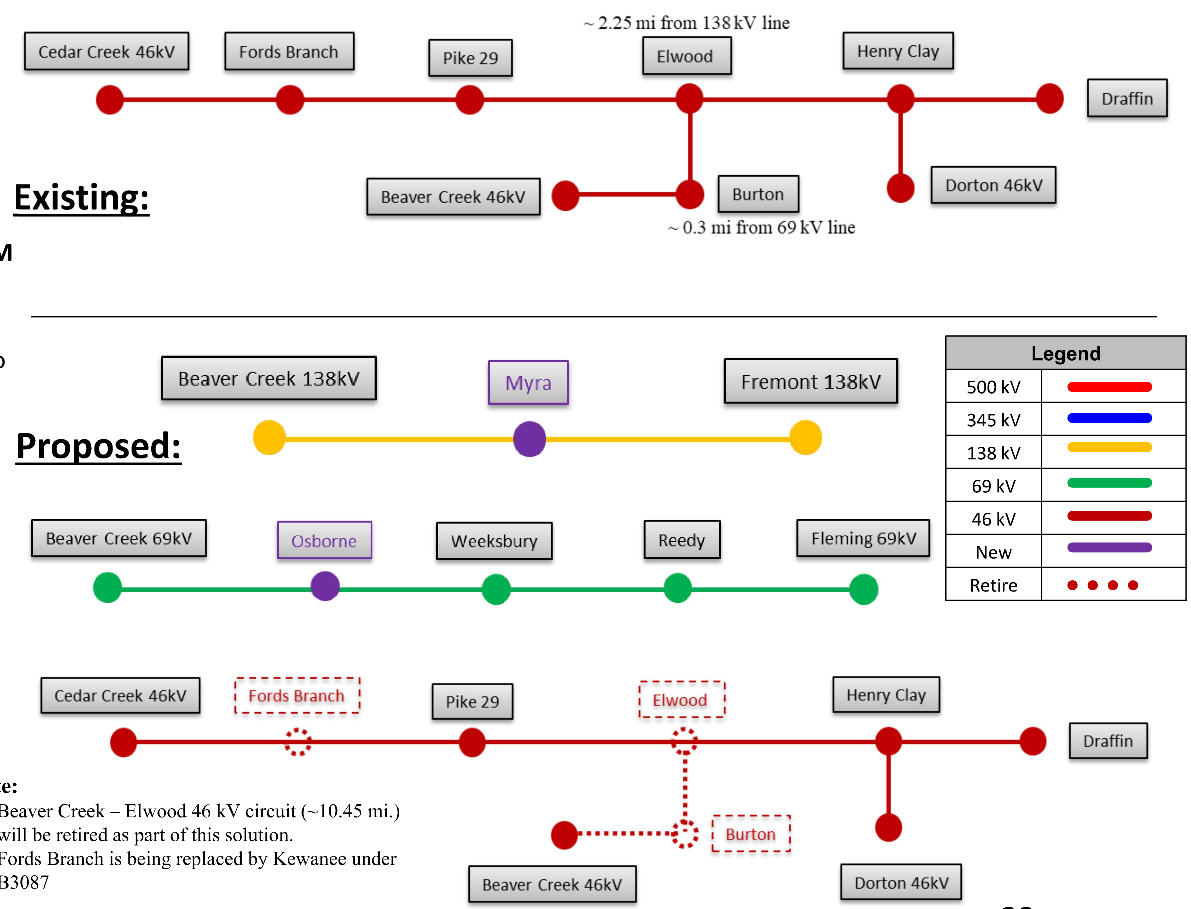
Total Estimated Transmission Cost: $26.16 M

Projected In-Service: 11/31/2024

Supplemental Project ID: s2436.1-.12

Project Status: Scoping

Model: N/A



Note:
- Beaver Creek – Elwood 46 kV circuit (~10.45 mi.) will be retired as part of this solution.
- Fords Branch is being replaced by Kewanee under B3087

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Number: AEP-2020-AP026

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Previously Presented:

Need Meeting 03/19/2020

Solutions Meeting 11/20/2020

Project Driver:

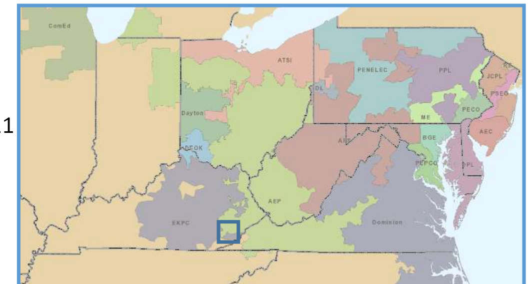
Equipment Condition/Performance/Risk

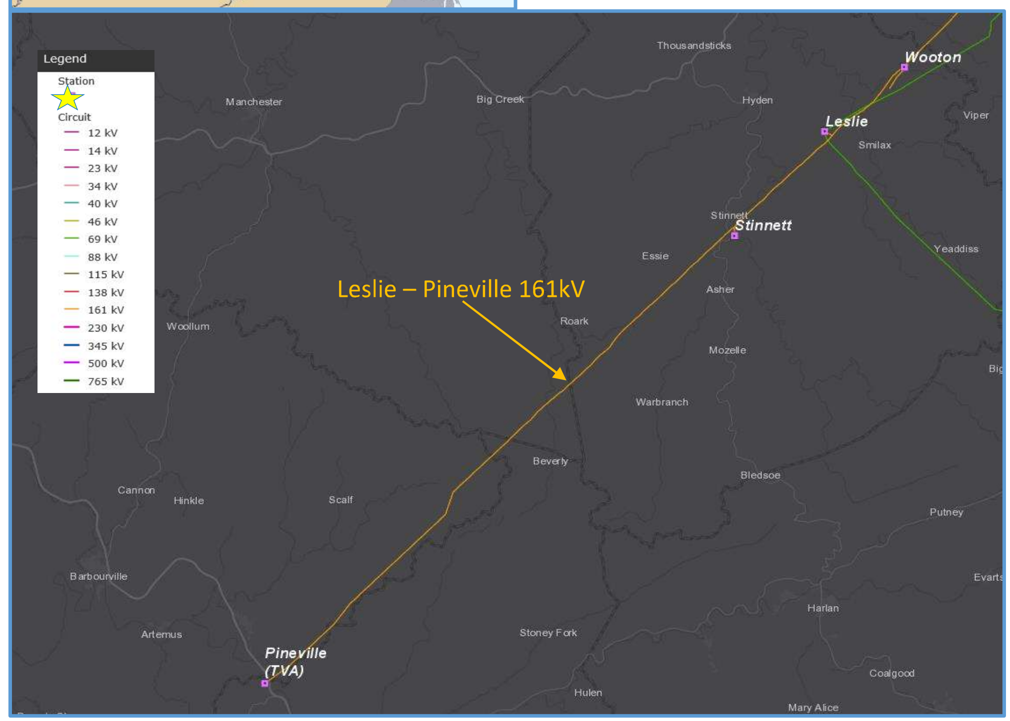
Specific Assumption Reference:
AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:
Line Name: Wooton – Pineville 161kV
Line Section: Leslie – Pineville 161kV
Original Install Date (Age): 1942
Length of Line: ~34.24 mi
Total structure count: 189
Original Line Construction Type: Wood
Conductor Type: 500 KCM COPPER
Momentary/Permanent Outages and Duration: 12 Momentary and 5 permanent Outage
CMI (last 5 years only): 26,096 minutes
Line conditions:

Leslie – Pineville line section:

- 130 structures with at least one open condition, 69% of the structures on this circuit.
- 221 structure related open conditions : affecting the crossarm, knee/ vee brace, or pole including rot, split, woodpecker, damaged, loose, and bowed conditions
- 2 open conditions related to the shielding wire, including broken strands
- 3 hardware related open conditions related to insulator, conductor hardware, or shield wire hardware, including broken, missing bolt, and worn





AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Continued:

Line Section: Wooton – Leslie 161kV

Original Install Date (Age): 1942

Length of Line: ~4.68 mi

Total structure count: 23

Original Line Construction Type: Wood

Conductor Type: 500 KCM COPPER

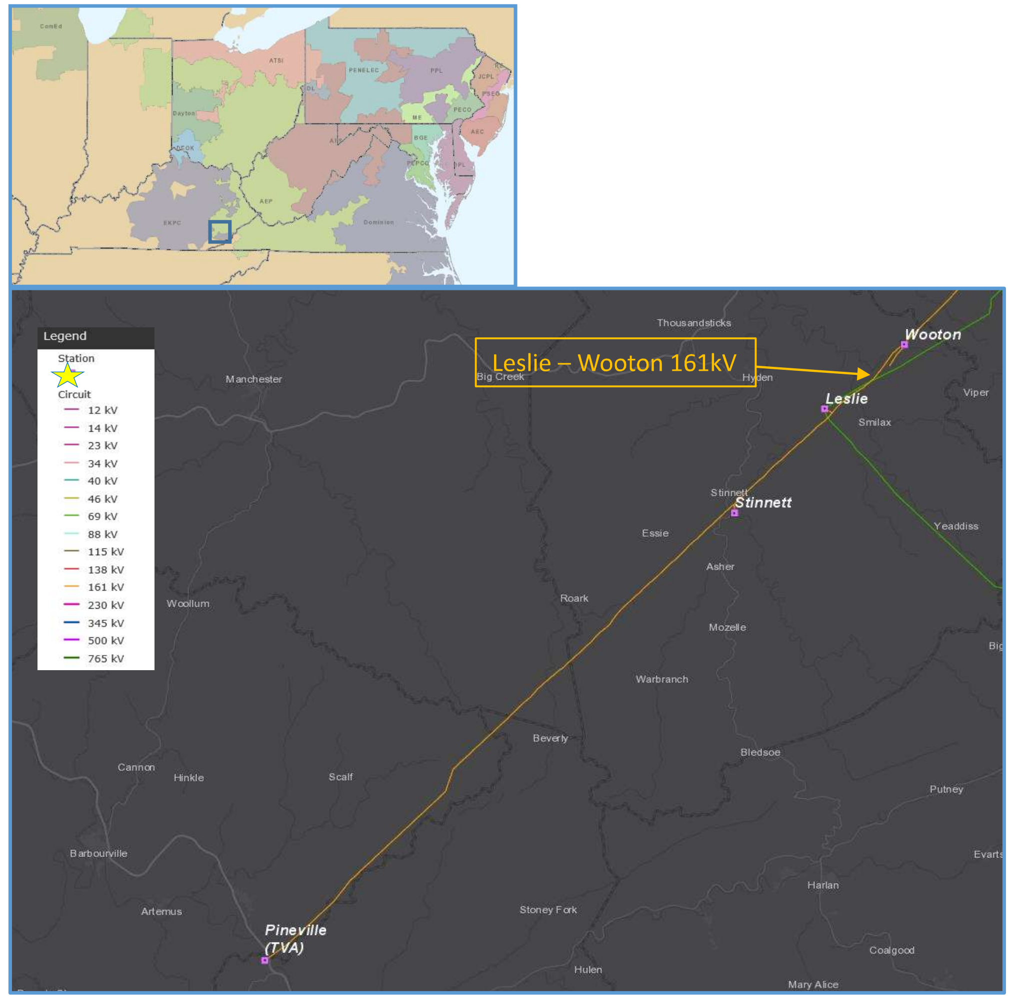
Momentary/Permanent Outages and Duration: none in last five years

CMI (last 5 years only): none in last five years

Line conditions:

Leslie – Wooton line section:

- 17 structures with at least one open condition, 74% of the structures on this section.
- 32 structure related open conditions including: crossarm or pole including rot, insect damage and woodpecker damage



AEP Transmission Zone M-3 Process
Wooton – Pineville 161kV Rebuild

Need Number: AEP-2020-AP026

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/08/2021

Selected Solution:

- At Wooton station, upgrade relaying to accommodate new OPGW fiber protection. **Estimated Cost: $1.1 M (s2428.1)**
- At Leslie station, reconductor the 161kV Bus, Relaying upgrades towards Wooton and Pineville, Replace 161kV MOAB W, Replace 161kV XF#1 high side switch. Install DICM. **Estimated Cost: $1.2 M (s2428.2)**
- Remote end work at Hazard substation **Estimated Cost: $0.03 M (s2428.3)**
- Rebuild approximately ~40 miles of Wooton – Pineville 161kV line to address the identified asset condition needs. This work also includes line removal work as well as access road construction. Majority of proposed line rebuild is to be constructed on existing center line. **Estimated Cost: $115.0M (s2428.4)**
- Expand existing ROW for the Wooton – Pineville 161kV line. **Estimated Cost: $8.5 M (s2428.5)**
- Relocate ~0.32 mi 69kV Leslie – Clover Fork which includes of one structure and reconfiguration of the existing line to cross underneath the proposed Wooton-Stinnett 161kV Line. **Estimated Cost: $0.7 M (s2428.6)**
- At Stinnett station, upgrade relaying to accommodate new OPGW fiber protection. Provide transition, entry and termination for OPGW connectivity to the Hazard-Pineville fiber route. **Estimated Cost: $0.7M (s2428.7)**
- Provide transition, entry and termination for OPGW connectivity at Leslie substation. **Estimated Cost: $0.1 M (s2428.8)**

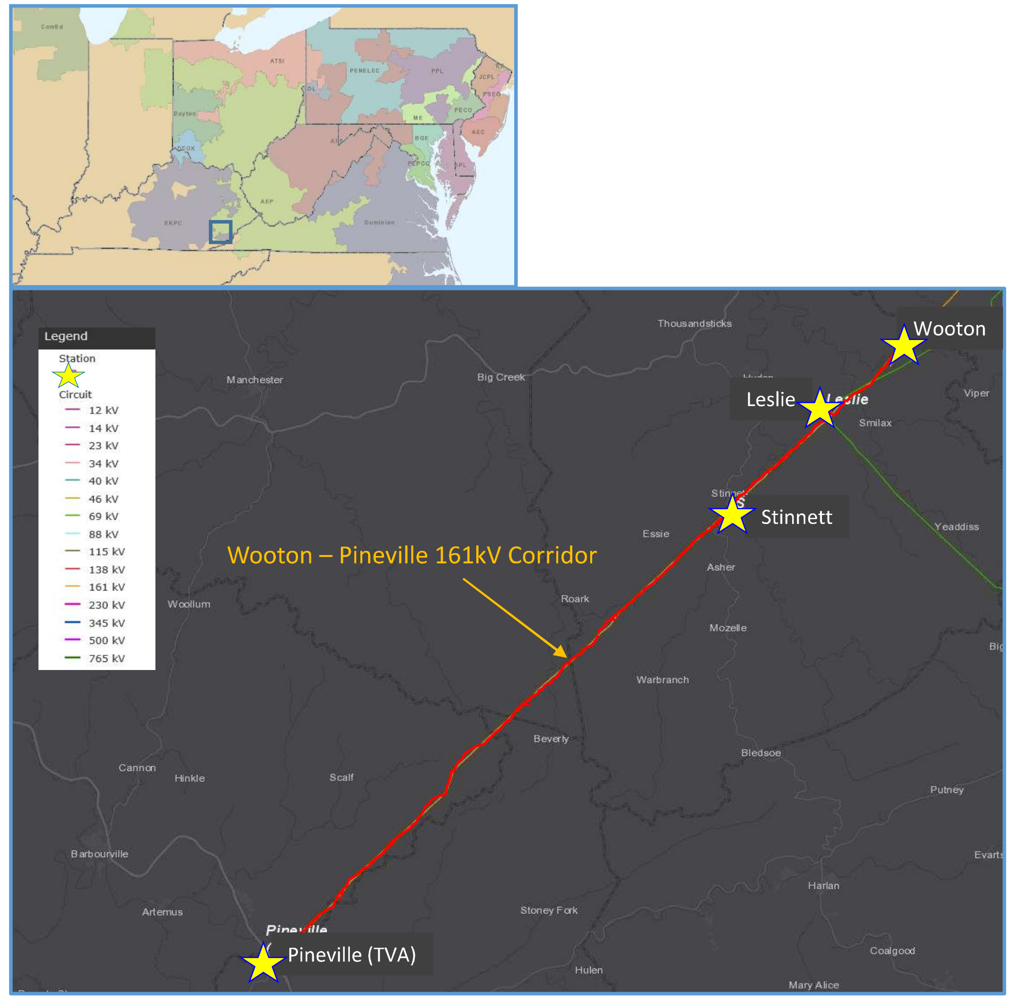
Estimated Cost: $127.33 M

Projected In-Service: 11/31/2027

Supplemental Project ID: s2428.1-.8

Project Status: Scoping

Model: N/A



AEP Transmission Zone M-3 Process
Falcon – Middle Creek

Need Number: AEP-2018-AP010

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/20/2020

Previously Presented:

Needs Meeting 11/29/2018

Solutions Meeting 12/18/2019

Project Driver:

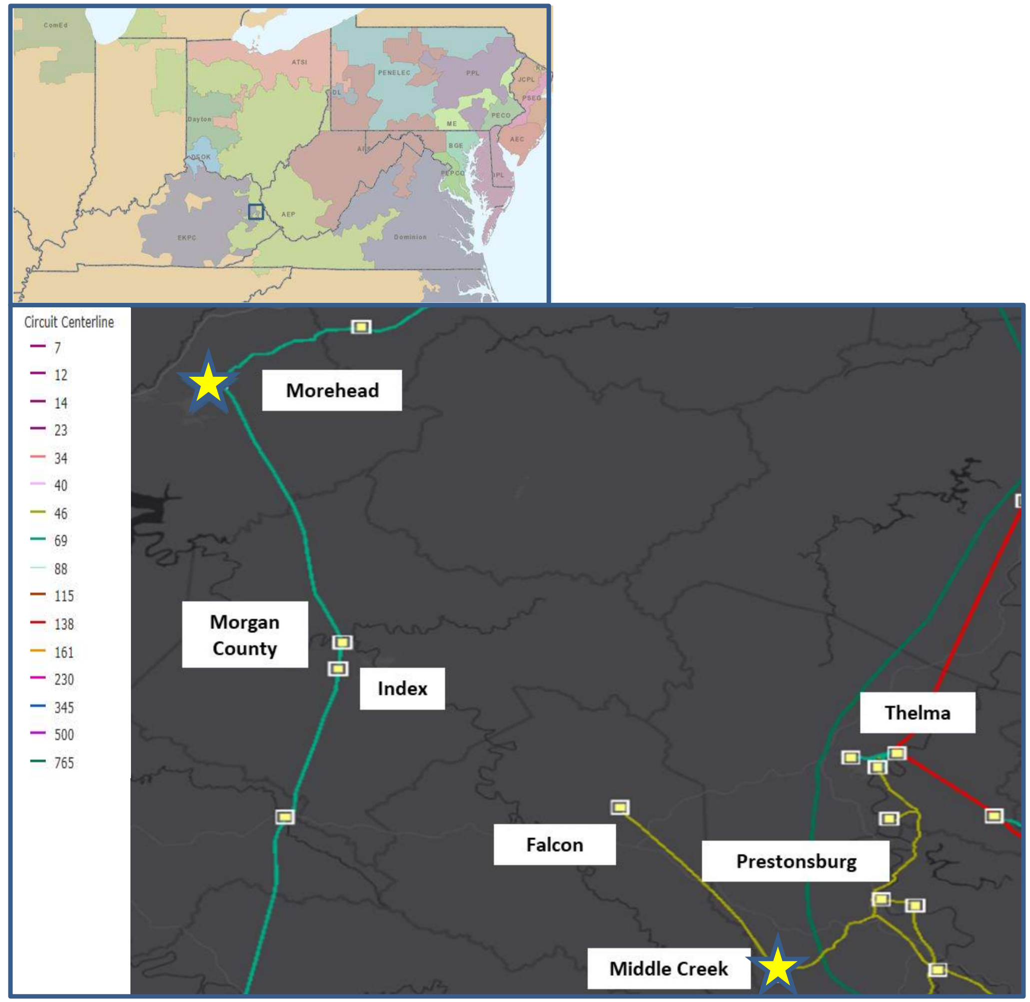
Equipment Condition/Performance/Risk

Specific Assumption Reference:

AEP Guidelines for Transmission Owner Identified Needs (AEP Assumptions Slide 8)

Problem Statement:

From 2013-2018 the Falcon –Prestonsburg 46 kV circuit (~ 23 miles) has experienced 19 momentary and permanent outages. Over the last three years the circuit has experienced 1.77 million customer minutes of interruption. The ~14.5 mile 46 kV line section between Falcon and Middle Creek has 84 category A open conditions associated with the structures that make up the line. These conditions include damaged/rotted poles and damaged guy wires, cross arms. The majority of this line utilizes 1950s wood structures and 3/0 ACSR conductor. The ~8.5 mile 46 kV line section between Middle Creek and Prestonsburg has 27 category A open conditions associated with the structures that make up the line. These conditions include damaged/rotted poles and damaged guy wires, cross arms. About half the structures that make up the line are 1940s wood structures with the majority of the line utilizing 1/0 Cu. conductor.



AEP Transmission Zone M-3 Process
Falcon – Middle Creek

Need Number: AEP-2018-AP010

Process Stage: Submission of Supplemental Project for inclusion in the Local Plan 04/20/2020

Selected Solution:

- **Phase 1:**
  - Install a 2MW BESS at Middle Creek substation. (**S2200.1**) **Estimated Cost: $9.7M**
- **Phase 2:**
  - Rebuild ~8.5 miles of 46 kV line between Prestonsburg and Middle Creek station. (**S2200.2**) **Estimated Cost: $25.5M**
  - Retire ~14.5 miles of 46 kV line between Falcon and Middle Creek. (**S2200.3**) **Estimated Cost: $6.1M**

Estimated Cost: $41.3 M

Projected In-Service:

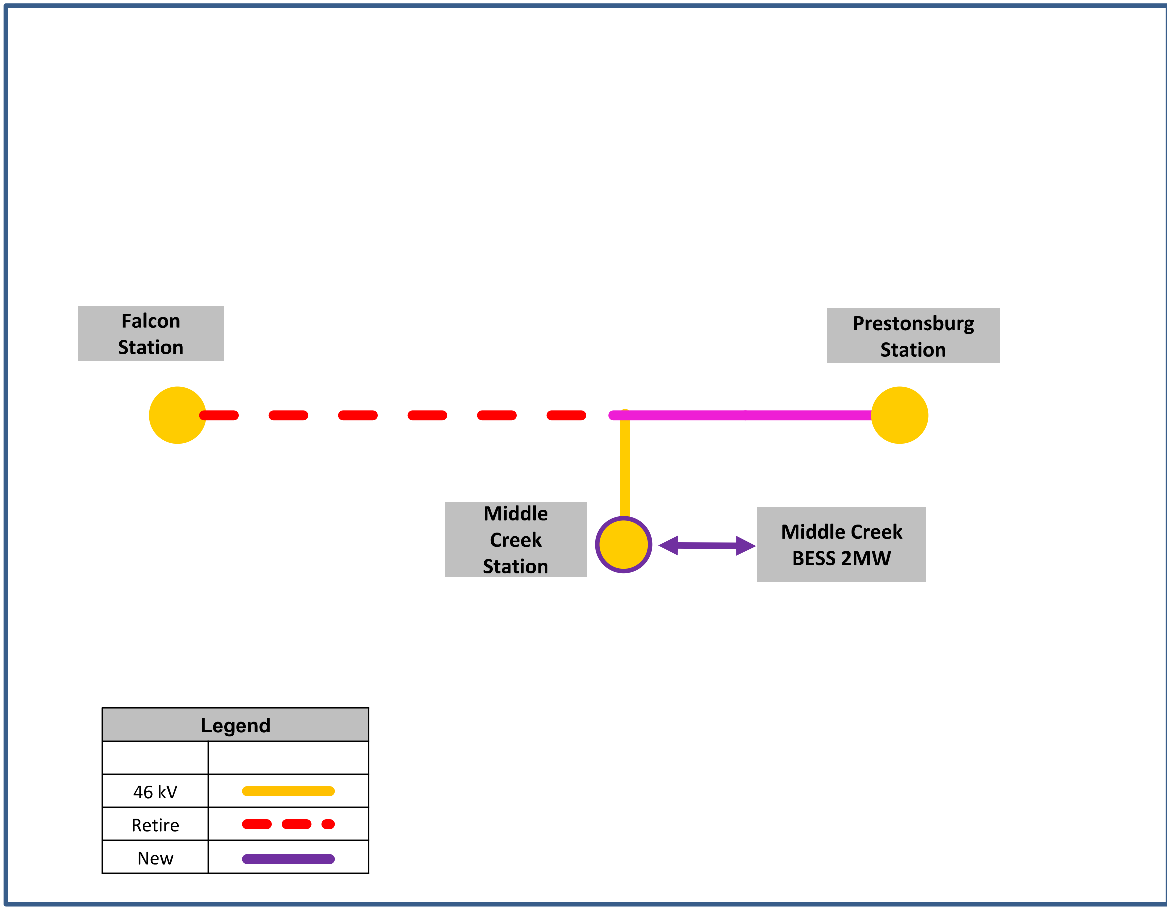
Phase 1: 12/1/2020

Phase 2: 4/1/2023

Supplemental Project ID: S2200.1-.3

Project Status: Scoping

Model: N/A



DATA REQUEST

KPSC 1_13 Refer to the IRP, Volume A, Section 4.2.2, page 84. Provide the methodology and supporting rationale for Kentucky Power's avoided capacity and energy costs.

RESPONSE

For this IRP, the estimated transmission and distribution avoided capacity costs to serve load is calculated for both the transmission and distribution systems by dividing each system's total annual plant investment (plant additions) by the estimated peak load served (peak demand) for each of the Transmission (All Transmission Load) and Distribution (Company Load) systems. This analysis is done based on historical information (3 year period) and an overall average value for this period is determined. Estimated carrying costs are applied to estimate the final annualized $ / kW – yr values for both Transmission and Distribution.

Energy and capacity values used to develop the benefits associated with energy efficiency measures are shown in Section 6.2 of the IRP which is the fundamental forecast.

Witness: Gregory J. Soller

DATA REQUEST

KPSC 1_14 Refer to the IRP, Volume A, Section 5, pages 86-90. Refer also to the IRP, Volume A, Section 3.2, Figure 12, page 55. Also refer to the IRP, Volume A, Section 5, Table 6, page 90. Provide an update to Table 6 by including the start cost of $79/MW in the calculation of Variable Operation and Maintenance (VOM) costs. Compare that amount the VOM for natural gas combined cycle (NGCC) in Table 5 on page 88.

RESPONSE

The VOM for the NGCT would be $1.84/MWh based on the number of starts and total energy output it has in the REF scenario under the reference portfolio. The VOM for the Multishaft NGCC is $2.03/MWh, while the VOM for the Single Shaft NGCC is $2.73/MWh.

REF Scenario	F-Class CT (240 MW)	NGCC 2x1 (1083MW)	NGCC 1x1 (418MW)
VOM	1.84/MWh	2.03/MWh	2.73/MWh

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_15 Refer to the IRP, Volume A, Section 5.21, pages 87–88, Section 5.31, pages 89–90, and Section 5.4, pages 93–96. Provide a comparison of the operational performance of the NGCC, natural gas combustion turbine (NGCT), wind, and solar resources during seasonal peak days.

RESPONSE

Please see KPCO_R_KPSC_1_15_Attachment1.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_16 Refer to the IRP, Volume A, Section 5 and Exhibit D. Explain why all the resources listed in Exhibit D are not discussed in Section 5.

RESPONSE

It was intended that all resources listed in Exhibit D would be discussed in Section 5. The Company has not identified any resources listed in Exhibit D that are not discussed in Section 5.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_17 Refer to the IRP, Volume A, Section 5.2.1, page 87, footnote 15.
a. Explain whether the partial ownership option of a NGCC unit was explicitly made available to the AURORA model as a resource option.
b. Explain whether any of American Electric Power's (AEP) other subsidiaries are in need of additional generation such that possible partial ownership of a NGCC unit with Kentucky Power is being considered

RESPONSE

a. A partial ownership of a NGCC unit was not modeled for this IRP.

b. Kentucky Power is not aware of current opportunities for partial ownership of a NGCC unit with one or more of its AEP affiliates.

Witness: Brian K. West (subpart b.)

Witness: Thomas Haratym (Charles River and Associates) (subpart a.)

DATA REQUEST

KPSC 1_18 Refer to the IRP, Volume A, Section 5.3, page 88.
a. Explain which generation technologies can also provide ancillary services and whether the ability to provide ancillary services was explicitly included in the AURORA modeling. If not, explain why not.
b. Explain whether lithium-ion batteries were modeled as generation resources.

RESPONSE

a. As discussed in Section 5.3 of the IRP on peaking resources, Gas CT, gas aero, gas reciprocating engines, and Li-ion batteries are capable of supplying ancillary services. The ability to provide ancillary services was not modeled due to the high uncertainty of ancillary service markets.

b. As discussed in IRP Section 5.3.4, Li-Ion batteries were modeled as a utility scale, supply-side generation resource. These resources were modeled based on their energy arbitrage opportunities and their capacity value to the portfolio.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_19 Refer to the IRP, Volume A, Section 5 and Exhibit D, page 218.
a. Confirm that each resource in Exhibit D was made available to the AURORA model.
b. Explain whether Big Sandy Unit 2 was made available to the AURORA model as a resource option based on the assumption it will be in use until 2040.
c. If Big Sandy Unit 2 were made available to the AURORA model as a resource option, provide the anticipated scheduled maintenance that would be performed and the ongoing costs.

RESPONSE

a. Confirmed, each resource in Exhibit D was made available to the AURORA model.

b. The Company assumes Staff intended to refer to Big Sandy Unit 1. Big Sandy Unit 2 was retired in 2015. Big Sandy Unit 1 was made available until 2041.

c. The Company assumes Staff intended to refer to Big Sandy Unit 1. Big Sandy Unit 2 was retired in 2015. The maintenance outages are schedule annually during April and mid-September through October (please see KPCO_R_KPSC_1_19_ConfidentialAttachment1). A schedule of the assumed ongoing costs is shown in KPCO_R_KPSC_1_19_Attachment2.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_20 Refer to the IRP, Volume A, Section 5.3.1, page 89, Section 5.3.2, page 90, and Exhibit D, page 218.
a. Explain how the F Class 240 MW NGCT, including operating characteristics modeled in AURORA, compares to the GE 9E series NGCT.
b. Provide an update to Exhibit D to include Big Sandy Unit 1 under the assumption that it would not retire till 2040.
c. Provide an update to Exhibit D, including Big Sandy Unit 1, that contains each resource's winter capacity, the estimated summer and winter unforced capacity, the modeled retirement dates, and the effective load carrying capability.

RESPONSE

a. The 9E is produced in smaller sizes (up to 150 MW vs over 200 MW) and has lower efficiency (approx. 0.5 MMBtu/MWh higher heat rate).

b. Please see KPCO_R_KPSC_1_20_ConfidentialAttachment1 for the requested information.

c. Please see KPCO_R_KPSC_1_20_ConfidentialAttachment1 for the requested information.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_21 Refer to the IRP, Volume A, Section 5.3.4, page 90; Section 5.6, pages 105–110; and Exhibit D, page 218.
a. Explain how the model can properly evaluate these resources when costs are incurred to charge these resources.
b. To the extent that energy is required to charge the battery, explain why the emissions from that generation are not attributed to the overall characteristics or the cost of the battery.
c. Explain why not attributing those emissions and the resulting costs to the battery within the AURORA and PLEXOS models does not lead to underestimating true battery costs relative to other potential resource options.

RESPONSE

a. The model optimizes net revenues by considering the cost of energy to charge and discharge in each hour. Round-trip efficiency (i.e. energy output divided by energy input) is also taken into account.

b. Costs associated with estimated emissions from grid supplied energy would be assumed to be part of the associated energy price to charge a battery.

c. See response to (b).

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_22 Refer to the IRP, Volume A, Section 5.4.1, page 94 and Exhibit D, page 218.
a. Explain whether Kentucky Power anticipates locating the wind resources referenced in its service territory. If not, explain where Kentucky Power expects the wind resources will be located.
b. Provide and explain wind speed and elevation charts that demonstrate that there is sufficient wind resources available in Kentucky Power's service territory sufficient to support utility scale wind turbine generation.
c. Explain whether Kentucky Power anticipates owning the wind generation facilities or signing power purchase agreements (PPAs).
d. Explain how there can be no variable O&M with a mechanical windmill as shown in Exhibit D.

RESPONSE

a. Kentucky Power evaluated the PJM queue for potential wind resources. While it is not anticipated that wind resources may be located within the service territory, the PJM queue suggests wind resources could be located within surrounding states to Kentucky.

b. For this IRP, the Company assumed that wind resources would likely be located at sites of appropriate resource as required, including outside of the service territory.

c. The decision to own or sign a Purchase Power Agreement (PPA) would be made as part of the analysis performed during the RFP process.

d. Per Section 5.1 of the IRP, technology costs relied on EIA AEO's 2022 report as a starting point. All wind O&M costs represented in the modeling are embedded in the full-service agreement arrangement under which an O&M contractor provides labor, management, and parts replacement (including unscheduled parts replacement) for the WTGs, collection system, and substation. This service agreement is represented in the IRP through a fixed operating cost.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_23 Refer to the IRP, Volume A, Section 5.4.2, page 96. Describe and explain the current status of the solar resources Kentucky Power has under development.

RESPONSE

Kentucky Power executed a lease option on four parcels of property, approximately 2,195 total acres, in the Hazard, KY area. It is a six-year option term with three two-year option renewals. The Company submitted a GIA request with PJM in September 2021 for a 100 MW solar project to be constructed on this site. Due diligence work continues on the site while the GIA request works through the PJM interconnection approval process.

Witness: Brian K. West

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_24 Refer to the IRP, Volume A, Section 5.5.3, page 102 and Exhibit D, page 218.
a. Explain what the "[s]tart cost of $79 / MW" in footnote F of Exhibit D represents.
b. Explain whether there is a utility scale polymer electrolyte membrane (PEM) electrolyzer plus hydrogen powered combustion turbine (CT) or a hydrogen powered CT in the U.S.
c. Explain the rationale for the conclusion that the levelized cost of energy (LCOE) for both types of hydrogen CTs is not applicable as indicated in Exhibit D when both have fuel costs and variable O&M costs.
d. Explain whether the LCOE is used as an input into the AURORA or PLEXOS modeling. If so, explain how the model(s) account for zero LCOE on an equal basis with the other potential resources.

RESPONSE

a. The start cost of $79/MW is a modeling parameter derived from the U.S. Energy Information Administration's "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies" report. It represents "CT Major Maintenance VOM costs, which are based on a starts operating regime, with cost per start indicated."

b. The Company is not aware of any in the US currently.The IRP does not assume a utility scale PEM electrolyzer plus hydrogen powered combustion turbine is available at the present. This is an advanced generation resource modeled to be available in 2032. The Long Ridge Energy unit has an H-class gas turbine currently capable of burning between 15-20% hydrogen by volume.

c. The variable cost of hydrogen fuel is relatively high, therefore the unit rarely dispatches. As the quantity of energy produced approaches zero, the LCOE approaches infinity. Therefore, at such low levels of output, LCOE is not a relevant metric.

d. LCOE is not used in modeling, it is a byproduct of other parameters. The model uses costs and operating characteristics to evaluate overall competitiveness.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_25 Refer to the IRP, Volume A, Section 5.7, page 111. Explain whether Kentucky Power uses resources, such as the energy information administration (EIA), to determine avoided cost rates.

RESPONSE

No, it does not. However, Section 5.7 discusses the Short-Term Market Purchase (STMP) resource used in the modeling as the price and opportunity cost of capacity in the region. This was to allow the model an option to include a short-term capacity commitment in place of a long-term capacity resource to mitigate abrupt capacity shortfalls. Please also see the response to KPSC 1_51(a) for a description on the development of capacity prices.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_26 Refer to the IRP, Volume A, Section 6.3.2.1, page 118. Explain the drivers for the decline in natural gas prices from current levels through 2026.

RESPONSE

Gas prices were developed through a review of market forwards and long-term fundamental analysis. Over the first several years, forward market data informs the decline in expected prices. Over the mid and long term, the outlook is informed by EIA's 2022 Annual Energy Outlook which was selected as a key reference view in the industry. EIA's view is established based on supply and demand drivers. On the supply side, production increases over the outlook horizon. On the demand side, LNG exports increase as more liquefaction capacity is brought online. Overall, EIA's view expects balanced fundamentals and a fairly flat price trajectory over the long-term.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_27 Refer to the IRP, Volume A, Section 6.3.2.2, page 118. Explain the drivers for the decline in the Central Appalachian Basin (CAPP) coal prices from current levels.

RESPONSE

Coal prices were developed through a review of market forwards and long-term fundamental analysis. Over the first several years, forward market data informs the decline in expected prices. Over the mid and long term, coal prices are expected to be influenced by several supply and demand drivers. On the supply side, production costs are evaluated over time. On the demand side, the fundamental assessment evaluates how the interaction between natural gas and coal prices impacts coal plant dispatch and how other long-term U.S. power sector trends, particularly the expectation for continued coal retirements, impacts coal demand. Overall, the fundamental analysis expects a steady decline in coal demand over time, which drives reductions in coal prices as lower-cost mines become marginal and higher-cost producers exit the market.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_28 Refer to the IRP, Volume A, Section 6.3.2.3, page 119. Confirm that the CO_2 price is assumed to be applied to both new and existing natural gas and oil fired combustion turbines as well as NGCCs.

RESPONSE

Confirmed.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_29 Refer to the IRP, Volume A, Section 6.4, page 124. For the Clean Energy Technology Advancement scenario, explain the drivers of the more aggressive end-use electrification, which end uses are expanding, and how the customer demand patterns have shifted from the reference scenario.

RESPONSE

Under the Clean Energy Technology Advancement (CETA) scenario, load grows more quickly than under the Reference scenario driven by increased economic growth, deployment of electric vehicles, and greater building electrification. Changes to customer demand patterns relative to the reference scenario are outlined in Section 6.4.1. The higher load growth under CETA for the broader market is based on applying the Kentucky Power high load growth escalation rate to PJM more broadly.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_30 Refer to the IRP, Volume A, Section 6.4, page 124. In the Enhanced Carbon Regulation scenario, explain whether the higher natural gas prices from the cap and trade system include the effects from increased regulations on emissions emanating from the natural gas drilling and mining operations and from increased controls to reduce leaks from natural gas pipelines.

RESPONSE

ECR was a scenario developed to include higher natural gas prices based on a possible future outlook. The regulations apply to a stricter overall regulatory regime for gas production, rather than specific sub-sectors. The source of the gas price outlook for ECR is the EIA AEO 2022 Low Oil and Gas Supply Case which includes materially lower production levels vs the Reference case. EIA AEO was selected as a key reference view in the industry.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_31 Refer to the IRP, Volume A, Section 6.3.3, Figure 43, page 121.
a. Identify and describe the resource technologies referenced in Figure 43 that comprise long duration storage.
b. Explain the differences between the 4-hour storage and the long duration storage that account for the differences in effective load carrying capability (ELCC) assumptions.

RESPONSE

a. Long duration storage technologies include pumped thermal, flow battery, and compressed air. Please refer to IRP Section 5.6, which details Long Duration Storage Alternatives.

b. The long duration storage options are capable of storing and discharging energy up to 20-hours at full nameplate capacity. The basis for the ELCC is PJM guidance for the 2024/25 capacity auction. The ELCC was inferred to be 100% given that the rating that PJM guidance assigns 100% to 10-hr storage and 20-hr storage has an even greater ability to be available for peak time. 4-hour storage begins at 82% ELCC, but declines to 66% ELCC by 2037 as increments of new resources are expected to provide less additional capacity value as more of the resource is added to the system.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_32 Refer to the IRP, Volume A, Section 6.6.2, pages 140–141 and footnote 46, page 141.
a. Identify the other county for which historical weather data was used in the analysis.
b. Explain the wind elevation levels and average and sustained wind speeds that were taken in both Morgan County and the second Kentucky county that make these counties suitable as proxies for a utility scale wind farm.
c. Explain the locations suitable for utility scale solar facilities. Explain whether the fact that eastern Kentucky is mountainous and forested impacts the selection of suitable locations.

RESPONSE

a. Wind historical data were taken from 5 different years from Morgan County, KY, and solar historical data were taken from Carter County, KY.

b. The wind data for stochastic analysis was based on 13 mph average at 80 meters. Note, this was the basis for stochastic analysis and does not imply ultimate wind build location. Morgan County was selected as a proxy for wind data because it is representative of the Company's service territory. Please also see the Company's response to KPSC 1-22.

c. For purposes of the IRP analysis, the counties for wind and solar locations for stochastic analysis were selected based on higher wind and solar resource areas within Kentucky Power's service territory. Generally, more mountainous and forested terrain could present challenges to locating utility scale solar facilities, but any challenges would be site specific. However, the IRP does not analyze actual locations for any future facilities, and specific build sites would be selected during the RFP process.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_33 Refer to the IRP, Volume A, Section 6.6.2, pages 140–141.
a. Explain the source of the National Renewable Energy Laboratory (NREL) historical weather data.
b. Explain why weather data from 2008 through 2012 was used in the analysis instead of more recent data. Explain whether the fact that the data is potentially stale impacts the analysis and whether Kentucky Power considered utilizing more recent data.
c. Explain whether NREL weather data was used in the load forecast analyses, including specifically whether it was used in the statistically adjusted end-use (SAE) models.

RESPONSE

a. According to NREL : The Solar data comes from the National Solar Radiation Database (NSRDB), which according to NREL "is a serially complete collection of hourly meteorological data and three most common measurements of solar radiation." The wind data comes from the Wind Integration National Dataset (WIND) Toolkit, which is, according to NREL, "an instantaneous meteorological conditions from computer model output and calculated turbine power for more than 126,000 sites in the continental United States for the years 2007–2013."

b. Weather data can be relied on for long periods of time. In addition, NREL's Wind database only has data up to 2013. Thus, the NREL weather data was the best available information and is adequate for the purposes of stochastics analysis to capture variations in wind speed and solar irradiance. To maintain the same data set for both wind and solar, only 2008-2012 wind data was utilized.

c. No, the data was used for the stochastics analysis but not for the Load Forecast.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_34 Refer to the IRP, Volume A, Section 6.6.2, pages 141–142.
a. Explain whether the Reference scenario, as well as the various other scenarios, are modeling PJM/AEP zone or Kentucky Power service territories.
b. Explain how wind and solar output from Kentucky Power's service territory could move Kentucky Power's PJM zonal LMP.

RESPONSE

a. The AURORA-developed market scenarios model a system-wide outlook which includes the entire Eastern Interconnect (which includes all of PJM). Energy market pricing for the Kentucky Power portfolios in the model are based on a zonal price for the PJM AEP Zone.

b. The analysis in Section 6.6.2 focuses on stochastic impacts of changes to renewable profile on the generation output of the portfolio. No direct linkage between renewable output draws and pricing was implied.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_35 Refer to the Application, Volume A, Section 7.2.3, pages 149–150. Kentucky Power is using locational diversity of resources selected in portfolios as an indicator of reliability. Explain the meaning of locational diversity and how that aids portfolio reliability.

RESPONSE

For the purposes of the IRP, locational diversity in this context is referring to diversity of energy output of the Kentucky Power fleet. A more diverse energy mix implies less concentration of risk for any one fuel or technology. Please see IRP Section 7.2.3.3. This energy mix could simply be referred to as diversity of energy output, without using the term "locational."

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_36 Refer to the Application, Volume A, Section 7.2.3.1, page 149–150.
a. Explain why short term capacity purchases are excluded from the planning reserve indicator.
b. Provide the winter and summer evaluation results separately for the planning reserve indicator, including all workpapers supporting the results.

RESPONSE

a. The statement in the IRP Section 7.2.3.1 page 149 was a wording error. Short term capacity purchases were included in the planning reserve metric on the scorecard. The analysis was performed on the assumption that these were included. This correction does not alter the conclusion of the IRP.

b. Please see KPCO_R_KPSC_1_8_Attachment1 for the Capacity Charts and Reserves worksheet, rows 53 and 54. Toggle cell B1 to select the different portfolios.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_37 Refer to the IRP, Volume A, Section 7.3.1, pages 155–161.
a. Provide each of the portfolios in tabular form.
b. Provide an update to each portfolio based on Kentucky Power's winter capacity needs as determined by its load forecast, as opposed to Kentucky Power's PJM summer capacity obligations.
c. Explain how Kentucky Power plans to meet its winter capacity deficit.

RESPONSE

a. Please refer to IRP Appendix E for each portfolio in tabular form.

b. For this IRP, the Company performed a winter load optimization analysis as described in Section 7.3.2. under Reference conditions. A winter load optimization analysis for the other portfolios was not conducted. While the result of any analysis is uncertain, there is no basis to assume that the results on the portfolios analyses would be directionally different such that storage resources would be added to support the winter adequacy capacity position that is no longer met with solar resources in the summer optimized portfolios. That analysis would require a significant amount of resources and time comparable to the preparation of a new IRP.

c. For this IRP, Kentucky Power does not have a winter capacity deficit relative to its PJM obligation. The Company relies on its membership in PJM to support its specific winter load obligation.

Witness: Brian K. West

Witness: Gregory J. Soller

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_38 Refer to the IRP, Volume A, Section 7.3.1, pages 159. Explain why the CC Portfolio added only 418 MW of NGCC.

RESPONSE

The CC Portfolio included a single 1x1, 418MW resource forced in 2029 to replace the optimized selection of 480MW of CTs in the Reference Portfolio. This was the closest available option in terms of capacity of modeled natural gas resources to evaluate.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_39 Refer to the IRP, Volume A, Section 7.3.1, pages 155–161.
a. Explain why significant amounts of capacity purchases, 450 MW, are required in 2028.
b. Explain why the NGCC option was never selected in any of the scenarios in which the AURORA model was allowed to select any resource.

RESPONSE

a. Because the Mitchell Plant capacity would not be available for the entirety of the 2028/2029 PJM planning year, it was excluded from the portfolio for that PJM planning year. Thus, the Company would be short capacity and didn't anticipate it would be able to acquire adequate long-term resources to fill the need in this time period, and therefore capacity purchases would be necessary.

b. For this IRP, the NGCC was not economic versus the alternative resources within the model. This is a result of a combination of factors including capital costs, O&M costs, emissions costs and tax credits.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_40 Refer to the Application, Volume A, Section 7.4.3. page 166.
a. Provide an update to Table 19 showing the reserves annually for the summer and winter seasons. Include in the response the preferred portfolio.
b. Provide the work papers supporting Table 19 including updates in Excel spreadsheet format with all formulas, rows, and columns unprotected and fully accessible.
c. Explain whether the planning reserves measure results change if resources are evaluated based on ELCC.

RESPONSE

a. An update to Table 19 can be found in KPCO_R_KPSC_1_8_Attachment1, Capacity Charts and Reserves worksheet. For annual reserves for both summer and winter season, please see rows 53 and 54 on the tab "Capacity Charts and Reserves". Toggle cell B1, B3, and B4 to see all portfolios under all scenarios and seasons.

b. Please see KPCO_R_KPSC_1_8_Attachment1, "Capacity Charts and Reserves" worksheet. Toggle cell B1, B3, and B4 to see all portfolios under all scenarios and seasons.

c. The planning reserves measure results were based on the use of an ELCC, so the measure results would not change.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_41 Refer to the Application, Volume A, Section 7.4.3.1, page 167. Explain why Kentucky Power is planning to be capacity short during the winter season across all portfolios.

RESPONSE

As a member of PJM, the Company is obligated to meet the PJM Summer Coincident peak for planning purposes. Currently Kentucky Power does not have a PJM winter capacity requirement. For purposes of the IRP, Kentucky Power is assumed to meet its load needs through its membership in PJM.

Witness: Gregory J. Soller

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_42 Refer to the Application, Volume A, Section 6.4.3, page 128 and Section 7.4.4.1, page 169.
a. Explain whether transmission related costs including congestion for the 25 percent of solar facilities and the 100 percent of wind facilities not located in Kentucky Power's service territory were included in the AURORA modeling in formulating the Reference portfolio, any of the subsequent scenario portfolios, or the preferred portfolio. If so, explain which transmission related cost were included and how the model treated those costs.
b. Aside from the representative capital costs, explain whether any other costs for those portions of the solar and wind facilities not located in Kentucky Power's service territory were equated with the facilities located in the service territory.
c. Explain whether those portions of the solar and wind facilities not located in Kentucky Power's service territory are assumed to be located in Kentucky or outside the state.
d. Explain whether it makes a difference to the modeling costs if the facilities be located in the PJM AEP Zone.

RESPONSE

a. The Company only included an interconnection cost of $18.9/kW capex for each solar and wind resource in each portfolio.

b. All wind and solar facilities are assumed to have a uniform cost.

c. There was no assumption of where those facilities would be located within the modeling. These decisions will be made as part of the RFP process. Please also see the Company's response to KPSC 1-22 and KPSC 1-32.

d. New plant costs are not assumed dependent on PJM zones. Although cost profile can vary depending on location, Kentucky Power assumes a similar cost profile for other parts of Kentucky and surrounding states.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_43 Refer to the Application, Volume A, Section 7.4.3.2, page 167.
a. Provide an update to Table 20 showing the dispatchable capacity annually for each year through the end of the planning period. Include in the response the preferred portfolio and the seasonal capacity measures.
b. For each portfolio in Table 20, explain and show the annual decline in each dispatchable resource over the forecast period. Include in the response the preferred portfolio.
c. Explain the operational flexibility of each portfolio, including the preferred plan, when evaluated on a ELCC basis as opposed to an unforced capacity (UCAP) basis.

RESPONSE

a. Please see KPCO_R_KPSC_1_8_Attachment1 under tab Build Summary, rows D22 - D38. Toggle cell A1 to see other portfolio options.

b. Please see KPCO_R_KPSC_1_8_Attachment1 under tab Build Summary, rows D22 - D38. Toggle cell A1 to see other portfolio options.

c. For purposes of the IRP, ELCC is not a metric applicable to operational flexibility but only to accredited capacity towards the Company's PJM obligation.

The operational flexibility metric was presented on an ICAP basis only for the non-renewable (ML, BS, Gas CT and Storage) resources. Please see KPCO_R_KPSC_1_8_Attachment1 for the operational flexibility on a ICAP MW basis.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_44 Refer to the Application, Volume A, Section 7.4.4.1, pages 169–170.
a. Provide an update to Table 21 showing both UCAP and ELCC for each portfolio annually. Include in the response the preferred portfolio.
b. Explain whether the costs to extend Big Sandy to run till 2041 are included in the calculations in the Total CapEx Invested Inside Kentucky Power Territory column. If not, explain why not.

RESPONSE

a. Table 21 represents the new nameplate MW which is the basis for the estimated capital expenditures. Evaluating the Local Impacts metric on the UCAP capacity of the nameplate MW of resources would not change the estimated Total CapEx invested. However, to see an annual UCAP capacity for each portfolio, please see KPCO_R_KPSC_1_44_Attachment1.

b. No, as an extension of an existing resource, the additional CapEx was excluded from the Total Capex Invested Inside Kentucky Power Territory column.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_45 Refer to the IRP, Volume A, Section 7.5.1, Figures 80–81, pages 173–175.
a. Provide a detailed comparison of the Combined Cycle (CC) Portfolio and the Preferred Plan.
b. Explain in greater detail how the Preferred Plan was obtained by changing the CC Portfolio.
c. Kentucky Power stated the Preferred Plan is based on an uncertain future that could impact the company's capacity position, including uncertainty around intermittent resource availability and the intermittent resources' contribution to reserve margins. Explain the logic of how a Preferred Plan containing 1,500 MW of new intermittent capacity, a new 480 MW NGCT, and the extended life of the 295 MW Big Sandy unit provides sufficient capacity to meet both summer and winter reserve margin
obligations.

RESPONSE

a. The Preferred Plan (PP) includes the same resources as the CC Portfolio except that the CC resource was swapped for the CT resource that was consistently selected as part of the optimized portfolio analysis.

Comparing the Scorecard metrics of the Portfolios, the PP scores more favorably in several metrics while scoring very similarly in the 5 year CAGR and 15 year CPW metrics. More specifically, the PP, with the inclusion of the CTs results in improved reserve margin metrics, improved Operational Flexibility metric and a 5 year CAGR metric that was within 0.34% of the CC Portfolio and a 15 year CPW metric that was within 0.17% of the CC Portfolio.

b. The Preferred Plan was informed by the different Least-Cost Portfolios modeled and includes a diverse set of dispatchable and renewable generation resources.

The Preferred Plan scored competitively to the other Portfolios developed through the IRP process and modeling in Aurora. The Scorecard illustrates across multiple objectives and metrics, the competitiveness of the PP relative to all Portfolios including the CC Portfolio. The development of the IRP Objectives and Metrics along with portfolios to analyze was developed with key input from our IRP Stakeholders throughout the process.

The Company identified the Preferred Plan to include the renewable resources selected in the CC Portfolio while replacing the 418MW CC with 480MW of CT. This change was supported from the insights learned from the other optimized portfolios where the model identified capacity resources to fill the Company's PJM capacity obligation. The CT resource was included in the PP based on the analysis of the different least-cost portfolios that selected the CT as part of the modeled portfolios while also including a mix of additional renewable resources. In the near-term through 2029 specifically, the portfolio selection of renewable resources between the Reference, CETA, ECR, NCR and CC Portfolios were consistent with some small variations in the selection of wind or solar resources.

The No Wind and Winter Portfolios informed the process through a reliance on more solar and storage resources to fill capacity needs. In particular, the No Wind Portfolio modeled in response to Stakeholder feedback, identified a strong reliance on solar resources to provide a balance of energy and capacity value to fill the gap from wind resources selected in the other least cost portfolios. The No Wind Portfolio also selected the CT resource as part of its least cost solution. The Winter Portfolio analysis informed the process through primarily a swap of solar resources with storage resources in the early years through 2029. Wind resources were relied on as well with an increase in these resources over the Reference Portfolio through 2029.

As evident in the scorecard metrics and the relative competitiveness of the portfolios, the inclusion of the 480MW CT resource in place of the 418MW CC resource provides additional summer reserve margin of 14.7% relative to the Company's minimum PJM Obligation of 8.94%. The additional capacity length in the PP also serves to bolster the Company's reserve margin relative to a Winter Peak resulting in a 4% improvement on its net capacity position relative to a Kentucky Power specific load requirement over the CC Portfolio. The PP Operational Flexibility metric is also improved over the CC Portfolio as a result of the increased capacity amounts from the CT over the CC.

From a cost perspective, the Preferred Plan scored very similarly to the CC Portfolio with a 5 year CAGR metric that was within 0.34% of the CC Portfolio and a 15 year CPW that was within 0.17% of the CC Portfolio. While the Reference Portfolio identified the least cost plan, it included an amount of wind resources that were considered a risk in the long term plan supported by customer feedback and would be subject to additional reviews in future IRPs.

The PP provides Kentucky Power with a path forward and has identified the need for an all source RFP to examine in more detail the resource options available and how those resource characteristics will influence Kentucky Power’s cost to serve its customers.

c. The PP is developed recognizing the capacity accreditation that PJM confers to each resource type. Therefore, the PP, which includes 1,500 MW of renewable generation, 480 MW of NGCT, 295 MW of Big Sandy, and other capacity resources does satisfy Kentucky’s PJM capacity obligation of 8.94% as an FRR entity. The PP affords the Company optionality to meet its PJM capacity obligations as an FRR entity which are currently set to the Company's PJM coincident summer peak. The Company does not yet have a specific PJM winter capacity reserve margin obligation, but anticipates that PJM will establish a winter requirement in the future. Consequently, the Company evaluated a potential Winter requirement portfolio. The PP includes renewable resources was identified in all portfolio modeling to be part of a least-cost plan to meet the Company’s current obligations. Should the Company’s PJM capacity obligation transition to a seasonal construct that would include the Company’s winter peak in some form, the PP includes resources complimentary to the Winter Portfolio analysis such that storage resources selected as part of the optimized set of resources in the Winter Portfolio could be added without significant conflicts to the other optimized selection of resources.

Witness: Gregory J. Soller

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_46 Refer to the IRP, Volume A, Section 7.5.1, Figures 80–81, pages 173–175.
a. Explain how the AURORA model accounts for the different operational characteristics of the NGCT and NGCC.
b. Explain why Kentucky Power is not proposing to build additional gas generation earlier to help obviate the need for large, short term market purchases in 2028.
c. State when Kentucky Power will file a CPCN for the NGCT to be built and in service by 2029 pursuant to the preferred plan.

RESPONSE

a. Aurora takes into account the following - operational capacity, heat rate (fuel conversion efficiency), all variable costs (fuel, emissions, other variable costs), start cost, ramp rate, projected forced outages, maintenance outages, minimum up and down times, and minimum generating capacities. Both NGCT and NGCC have unique values for each parameter.

b. The construction of gas generation takes years to accomplish. Besides regulatory approvals, land must be secured, interconnection filing must be made with PJM and an interconnection agreement obtained, gas supply must be secured and constructed, project design must be completed, and equipment must be ordered and construction begun. Projects of this size and complexity take approximately 6 years to complete from start to finish.

c. The IRP was developed for long range planning needs to serve Kentucky Power's customers. The Company is currently evaluating all options with respect to how it will actually fulfill its future capacity needs, including considerations of NGCT recognizing constraints and opportunities around the location, timing, PJM interconnection, and commercialization of new NGCT in Kentucky. The Company expects that all of this will be informed by the results of the IRP, after it is completed. The Company will bring a CPCN application, if required, to the Commission after all analysis and once a final decision is made.

Witness: Brian K. West

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_47 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175. Explain whether Kentucky Power placed any limits on the amount of wind resources the AURORA model could choose in any of the portfolio analyses.

RESPONSE

Annual wind limits of 100MW/year for Tier 1 and 100MW/year for Tier 2 resources were included in the modeling. The total cumulative limit was 1200 MW.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_48 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175.
a. Explain why Kentucky Power is proposing to build 800 MW of solar.
b. Explain where Kentucky Power plans on building the solar generation in their service area.
c. Explain why Kentucky Power believes the solar facilities can be built and in use by 2029.

RESPONSE

a. 800MW of solar was selected as part of an optimized portfolio of resources in the CC Portfolio. This compares to the 650 MW of solar resources economically selected in the Reference Portfolio.

Solar resources include a measurable amount of accredited capacity to meet the PJM summer capacity obligation while also providing clean energy to Kentucky Power's customers. The additional amount of solar compared to the reference portfolio adjusts for the reduced amount of wind capacity between the portfolios.

b. The IRP does not model specific locations in the selection of resources. The location of any solar resources built in the Kentucky Power service areas would be identified through the RFP process. Please also see the Company's response to KPSC 1-32.

c. For this analysis, the Company assumed a duration including an RFP process, CPCN regulatory approval process and associated Engineering and Construction by a developer to take 3-4 years.

Witness: Gregory J. Soller

DATA REQUEST

KPSC 1_49 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175.
a. Does Kentucky Power believe that solar or wind capacity values should reflect 0 percent of expected contribution to winter peak capacity?
b. If 0 percent capacity contribution is expected from solar or wind to winter peak capacity, then explain how Kentucky Power anticipates on making up the capacity.
c. If 0 percent capacity contribution is not expected from solar or wind during winter peak capacity, explain why not.

RESPONSE

a. Wind winter ELCC was modeled as 16% in 2026 declining to 13% by 2030. Solar winter ELCC was modeled as 2%.

b. Please see the Company's response to subpart (a). Nonetheless, the IRP assumes that Kentucky Power will rely on its membership in PJM to support its winter capacity needs.

c. Wind resource is generally robust during winter across most hours of the day and will therefore contribute to the Company's capacity needs during winter peak hours. Solar output, while largely not available during peak winter hours, is still expected to make a small marginal contribution.

Witness: Thomas Haratym (Charles River and Associates)

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_50 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175.
a. Provide the results of the request for proposals for the wind and solar generation. If not possible, then identify when it could be provided.
b. Explain if Kentucky Power anticipates any issues with solar developers canceling projects due to interconnection delays and various labor, price, and supply chain issues as reported by other utilities. Include in the response if Kentucky Power will use renewable resources manufactured in the United States.

RESPONSE

a. The Company is currently working on an all source RFP and anticipates issuing sometime in the first quarter of 2024, or sooner if possible.

b. The Company will evaluate all proposals and identify a proposal scoring plan within the pending RFP, which may include scoring associated with renewable resources manufactured in the United States, as well as, other key performance characteristics related to the execution and completion of any proposed projects. Many issues increasing the risk of projects being cancelled are not unique to solar resources. The Company adapts to changes in circumstances as they occur.

Witness: Brian K. West

DATA REQUEST

KPSC 1_51 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175.
a. Explain how the price of capacity was determined in each year that the Preferred Plan calls for capacity purchases.
b. Explain how purchasing 407 MWs of capacity is economically feasible and does not create grid instability compared to building additional generation before having a capacity shortfall.
c. Provide the estimated annual cost of capacity purchases in the Preferred Plan.

RESPONSE

a. The capacity price level represents the opportunity cost of capacity in the region at which Kentucky Power capacity is valued. This was derived by CRA based on an outlook for supply and demand curves for the PJM RPM. See Section 5.7 of the IRP.

b. For purposes of the IRP it is assumed that 407 MW of capacity is available in the market and that PJM manages grid stability relative to capacity resources in PJM. For purposes of the IRP it is also assumed that capacity will be available in the market at prices lower than the full cost of new entry.

c. Please see KPCO_R_KPSC_1_51_Attachment1 for the requested information.

Witness: Thomas Haratym (Charles River and Associates)

DATA REQUEST

KPSC 1_52 Refer to the IRP, Volume A, Section 7.5.1, Figures 80 and 81, pages 173–175.
a. Identify and describe the DSM programs Kentucky Power intends to propose to the Commission.
b. Explain whether Kentucky Power will include potential dispatchable DSM as a demand-side resource addition.

RESPONSE

a. Kentucky Power has not yet identified the DSM program(s) that it intends to propose to the Commission. The Market Potential Study (MPS) conducted by GDS Associates, Inc. is still in the process of being finalized. Once the MPS is finalized, Kentucky Power management will be able to review the recommendations made by GDS and determine what programs to propose to the Commission.

b. Kentucky Power does not intend to include potential dispatchable DSM as an addition to its demand-side resource offerings. Kentucky Power has two demand response (DR) tariffs available for commercial and industrial customers including Rider D.R.S. (Demand Response Service) and Tariff C.S.-I.R.P. (Contract Service – Interruptible Power) in addition to one voluntary energy curtailment option with Tariff V.C.S. (Voluntary Curtailment Service). In an effort to control the cost of the MPS and administration of DSM programs, Kentucky Power instructed GDS not to include DR offerings in their estimates of energy efficiency potential savings.

Witness: Brian K. West

DATA REQUEST

KPSC 1_53 Refer to the IRP, Volume A, Section 7.5.1, footnote 48, page 175. Explain whether Kentucky Power has issued or is in the process of evaluating the results of the request for proposal (RFP).

RESPONSE

See the Company's response to KPSC 1-50.

Witness: Brian K. West

DATA REQUEST

KPSC 1_54 Refer to the IRP, Volume A, Exhibit H, page 338. Explain why there is not a December binary variable in the forecast equation.

RESPONSE

The inclusion of December binary variable would result in perfect multicollinearity between the constant (intercept) term and sum of all monthly binary variables. This would result in the coefficients not estimating properly.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_55 Refer to the IRP, Volume A, Exhibit H, page 338. There appears to be considerable overlap in the aprjun20, janjul20, and maroct20 binary variables and with the d1-d10 variables.
a. Explain the separate events represented by aprjun20, janjul20, and maroct20 and why a single binary variable covering the January through October 2020 would not suffice.
b. Explain why the d1-d10 binary variables do not adequately represent the events.

RESPONSE

a. The Covid 19 Pandemic caused unusual changes for residential customer counts. This variety of binary variables were used to correct unusual residuals that resulted with short-term increase in customer counts and drivers being affected by the Pandemic.

b. The monthly binary variables capture long-term monthly patterns. The variables noted captured short-term or one-time impacts on customer counts.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_56 Refer to the IRP, Volume A, Exhibit H, page 338. Explain the events represented by the feb21 and mar21 binary variables and why the d2 and d3 binary variables do not adequately represent those events.

RESPONSE

The feb21 and mar21 were used to adjust for anomalies in the residuals due to apparent oddities in the historical data. The variables d2 and d3 account for the average February and March monthly patterns, while the feb21 and mar21 account for these one-time occurrences.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_57 Refer to the IRP, Volume A, Exhibit H, page 338. Explain the events represented by the feb21 and the Mar21 binary variables and why the d2 and d3 binary variables to not adequately represent those events.

RESPONSE

See response to KPSC 1_56.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_58 Refer to the IRP, Volume A, Exhibit H, page 381.
a. Explain the events represented by the d02on, d04on, d07on, d093on, d13on, sep18on, aug19on, feb19on, and mar21on binary variables and why each event is not adequately represented by the other monthly binary variables.
b. Explain why there is not a December binary variable.

RESPONSE

a. The variety of binary variables are used to better capture some longer-term underlying changes in the customer count. These are used to better reflect how customer count has changed. A single binary would not have captured those changes.

b. See response to KPSC 1_54.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_59 Refer to the IRP, Volume A, Exhibit H, page 469.
a. Explain how the SalesPerHH, XHeat, XCool, and XOther variables were derived.
b. Provide the supporting documentation for the XHeat, XCool, and XOther variables.
c. Explain the events represented by the 7-Feb, Sep-95, and Nov-95 binary variables and explain why the other monthly binary variables do not adequately represent those events.
d. Explain why there is no December binary variable.

RESPONSE

a. & b. SalesPerHH is energy sales divided by number of household (residential customers). KPCO_R_KPSC_1_59_Attachment1 Appendix B describes the calculation of XHeat, XCool and XOther variables in Itron's SAE modeling framework.

c. These reflect outliers in the data not adequately explained by the drivers in the model. These are seen as one-time occurrences, while the monthly variables capture monthly patterns in usage not reflected in other drivers.

d. See response to KPSC 1_54.

Witness: Glenn R. Newman

Residential Statistically Adjusted End-Use (SAE) Spreadsheets – 2021 AEO Update

The Residential SAE spreadsheets and models have recently been updated to reflect the Energy Information Administration's (EIA) 2021 Annual Energy Outlook (AEO).

This EIA release is based on the 2015 Residential Energy Consumption Survey (RECS). The EIA forecast is an end-use based projection where 2015 is the "first" forecast year. The model starts with reported 2015 saturation rates and estimated stock efficiency. Saturation and stock estimates move forward from this point based on assumptions of relative technology efficiency, new appliance purchases, appliance costs (including rebates for utility efficiency programs), electricity prices, weather trends, and stock utilization. Results are calibrated into actual customer usage and the EIA short-term energy forecast.

The 2021 residential SAE spreadsheets and MetrixND project files include:

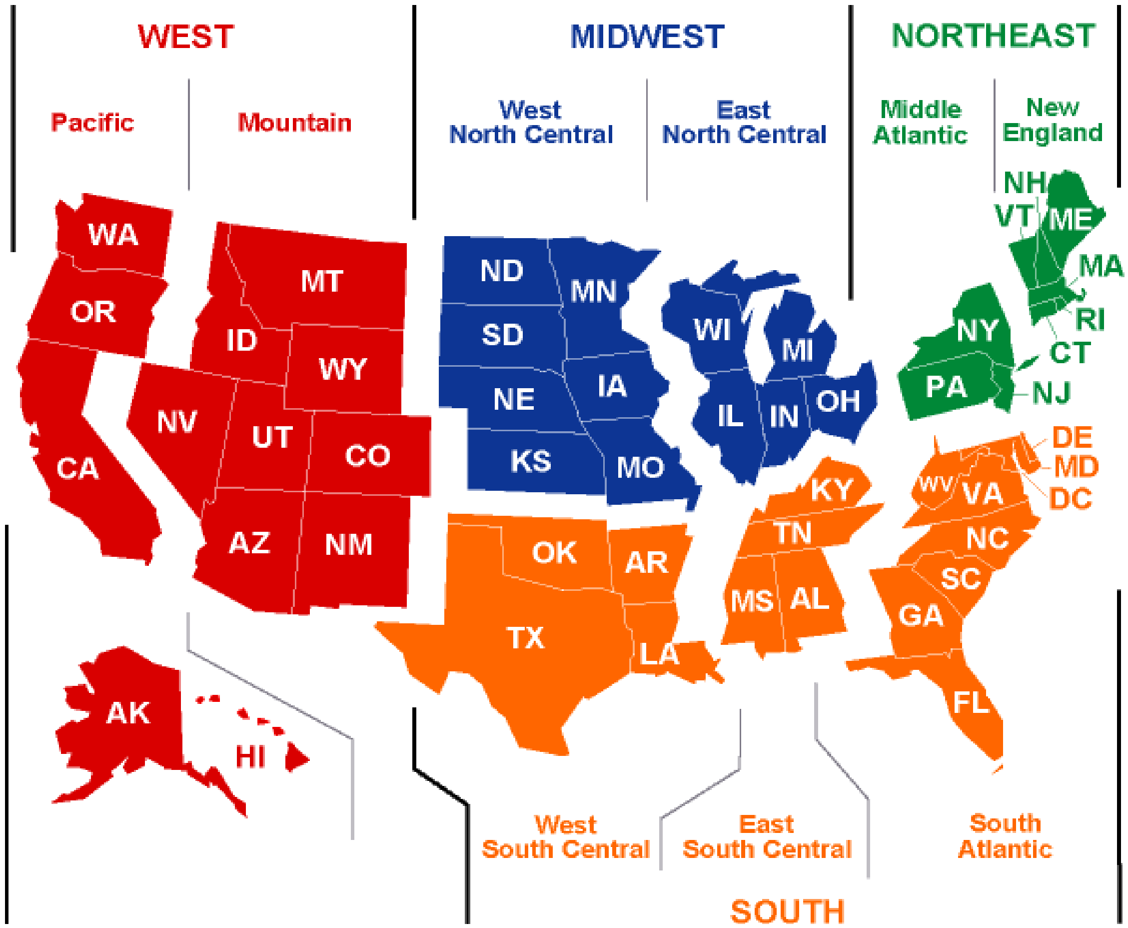
- Updated equipment efficiency trends
- Updated equipment and appliance saturation trends
- Updated structural indices
- Updated annual heating, cooling, water heating, and non-HVAC indices
- Updated regional sales forecasts

End-use saturation, efficiency, structural changes (building shell efficiency improvements and square footage projections), and base-year end-use energy use are combined to develop historical and projected end-use intensity estimates. Resulting intensities can be used in constructing heating, cooling, and other use variables for residential average use and total sales forecast models.

End-use saturation, efficiency, and average annual appliance use (UEC – Unit Energy Consumption) are derived from the National End-Use Model System (NEMS). While NEMS generates detailed end-use data, EIA is primarily concerned with the high-level projection of total energy requirements (measured in Btu) across all end-uses and sectors including transportation. From an electric or natural gas utility forecaster's perspective, it is the underlying end-use and technology level detail that provides insights into how individual residential and commercial customers are using electricity and natural gas, trends in end-use energy consumption, and what these trends imply for future electric and gas usage at the regional level.

EIA provides end-use detail for nine census divisions, depicted in Figure 1.

Figure 1: Forecast Census Divisions



The 2021 AEO forecast is based on the 2015 Residential Energy Consumption Survey (RECS). Base-year UECs, saturations, and stock efficiencies are derived from reported results. The NEMS model tracks end-use saturation, stock efficiency, and usage change over time as appliances are replaced, new appliances are purchased, and utilization changes with changing economic, price, and weather conditions. Appliance choice decisions are driven by appliance costs, efficiency options and standards, natural gas availability, and fuel prices for electricity and natural gas. Forecasts are developed for three housing types – single family, multi-family and mobile homes, for twenty end-uses, including:

- Resistance heating/furnaces
- Air-source heat pumps (heating)
- Ground-source heat pumps (heating)
- Secondary heating
- Central air conditioning
- Air-source heat pumps (cooling)
- Ground-source heat pumps (cooling)
- Room air conditioning
- Water heating
- Cooking

- 1st refrigerators
- 2nd refrigerators
- Freezers
- Dishwashers
- Clothes washers
- Clothes dryers
- TVs and related equipment
- Furnace fans
- Lighting
- Miscellaneous

In the Statistically Adjusted End-Use (SAE) model, detailed end-use data derived from the EIA forecasts is used to construct end-use intensities (kWh per household) that are then integrated into monthly heating, cooling, and other use model variables. These variables are then used to forecast utility-level residential and commercial sales through estimated linear regression models. Through the constructed model variables, forecast captures improvements in end-use efficiency driven by new standards, declining cost of high efficiency technology options, and availability of new end-use technologies.

To support econometric modeling, Itron maintains and updates historical end-use data trends that are consistent with the 2015 RECS and earlier RECS (i.e., the 2005 and 2009 RECS). Doing so sometimes requires adjusting historical end-use saturation and efficiency trends to reflect what EIA believes is the current state of appliance ownership, stock efficiency, and housing characteristics. The 2021 SAE spreadsheets reflect Itron's best estimates of historical end-use saturations, efficiency, and usage given EIA's 2015 base-year starting point and past estimates of end-use stock characteristics.

Electricity

EIA projects relatively flat total residential energy intensity (kWh per household) until well after 2030. After 2030, energy intensity turns positive largely as a result no additional end-use standards. Figure 2 shows U.S. total and base-use (excluding heating and cooling) energy intensity projections. Figure 3 shows U.S. heating and cooling intensities.

Figure 2: U.S. Residential Total and Base-Use Energy Intensities

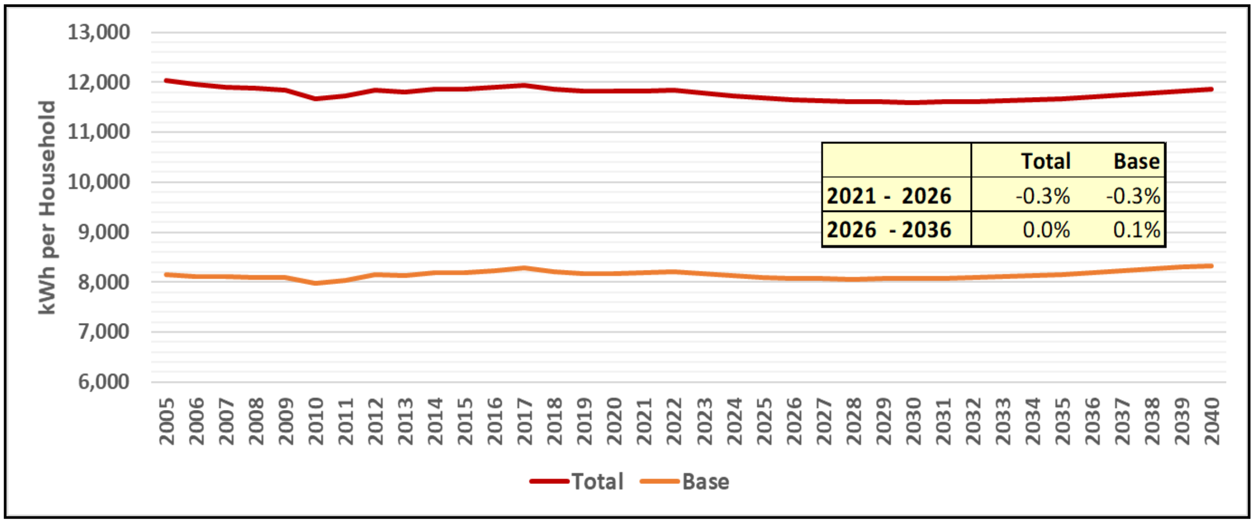
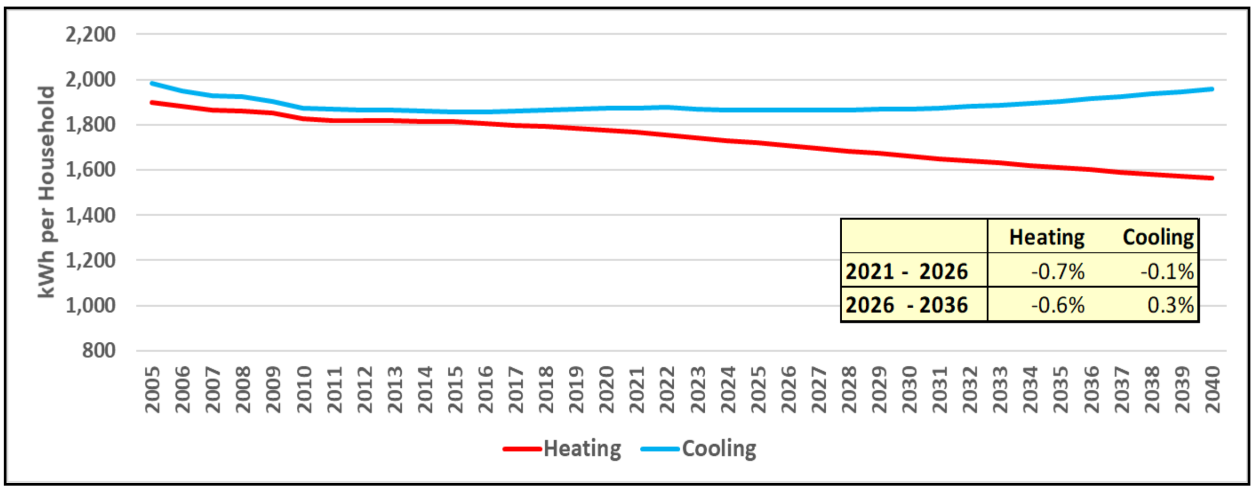


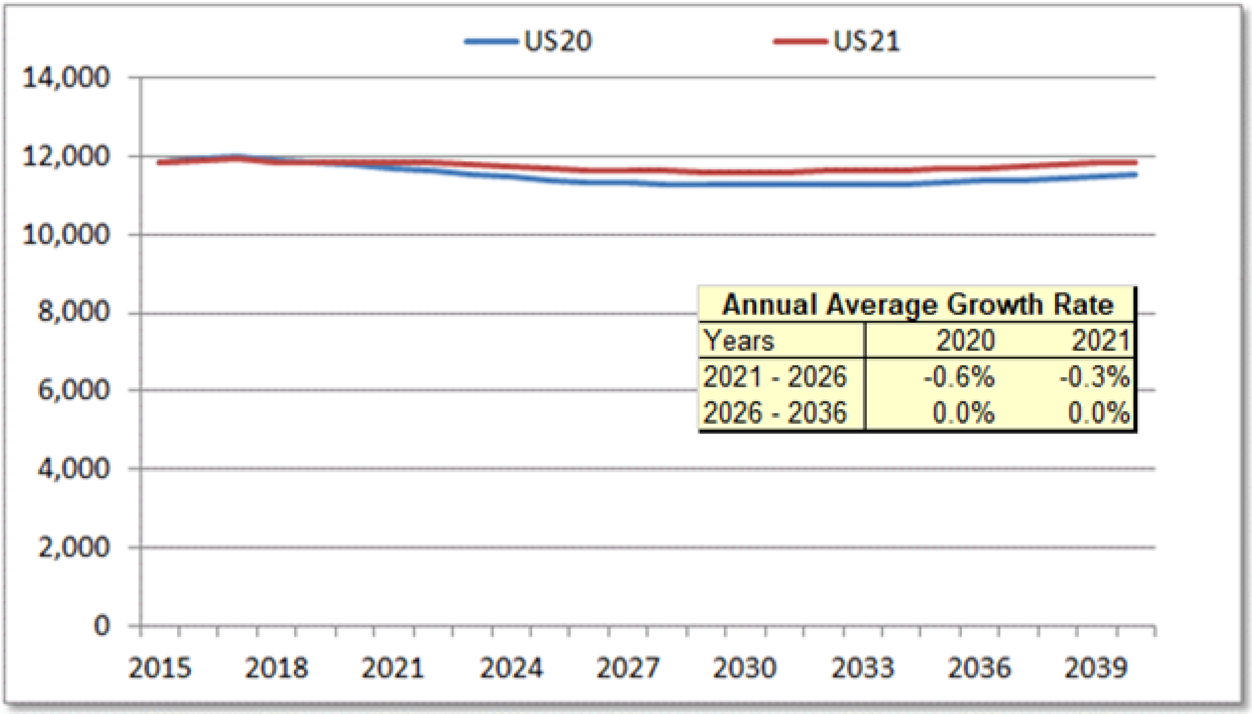
Figure 3: U.S. Residential Heating and Cooling Energy Intensities



Heating intensities, continue long-term downward trend as natural gas continues to gain market share and more efficient heat pumps gain share over resistant heat. Flat real electricity prices and improvements in furnace fan efficiency also contribute to declining heating intensity. Cooling intensities show small growth after 2027 as increasing cooling saturation is slightly stronger than efficiency improvements.

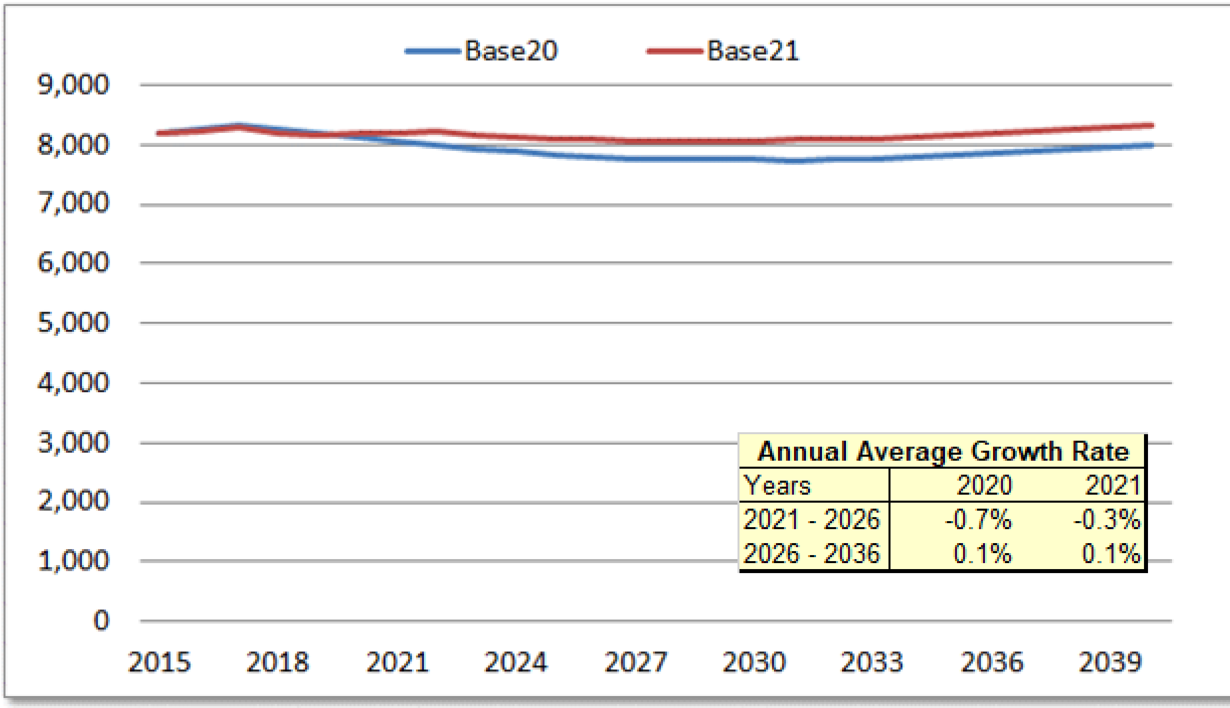
Error! Reference source not found. compares the U.S. SAE 2020 and SAE 2021 residential total household intensity projections.

Figure 4: U.S. Heating Intensity Projections (kWh/household)



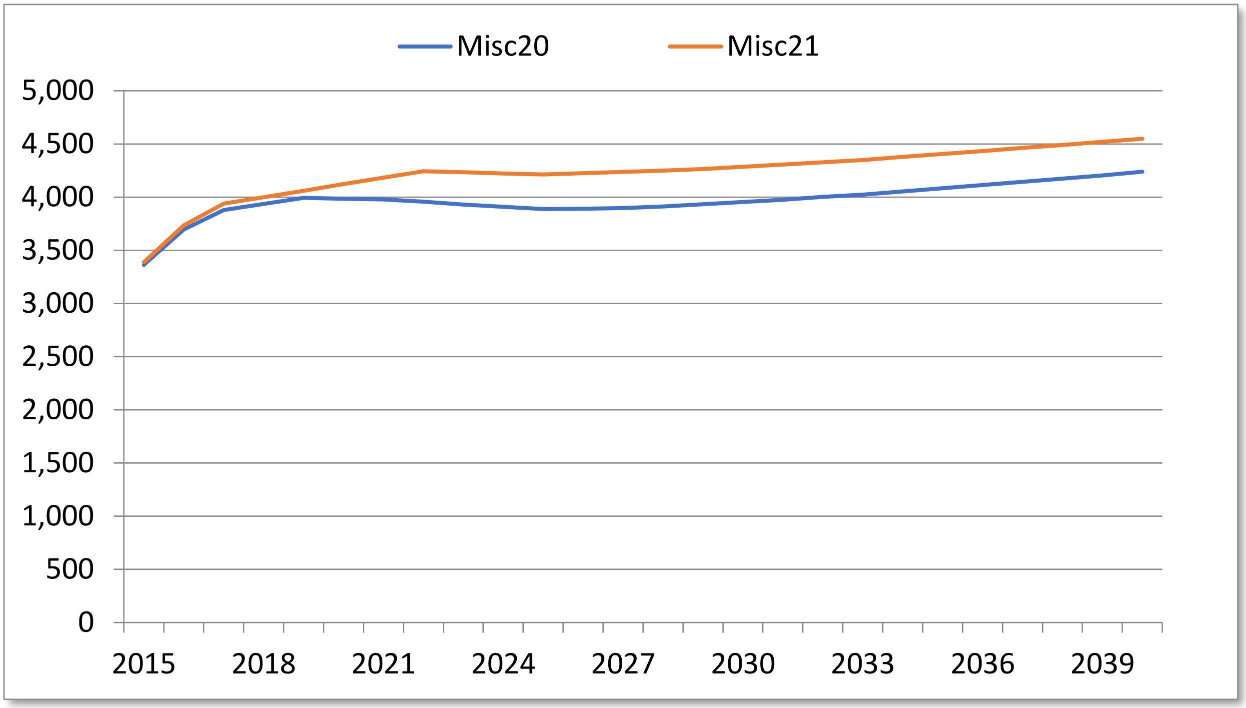
Total 2021 intensity is slightly higher than the 2020 forecast with the energy intensity declining at half the rate of the 2020 forecast through 2026. There is virtually no change in cooling and heating intensity. The difference lies in the base-use intensity as depicted in **Error! Reference source not found.**.

Figure 5: U.S. Base-Use Intensity (kWh/household)



Base-use loads (non-weather sensitive use) account for approximately 70% of residential sales. For most base end uses there is little to no difference between projected trends. The primary difference is the miscellaneous end use. **Figure 1** compares miscellaneous end use intensity projections.

Figure 1: U.S. Miscellaneous End-Use Intensity (kWh per Household)

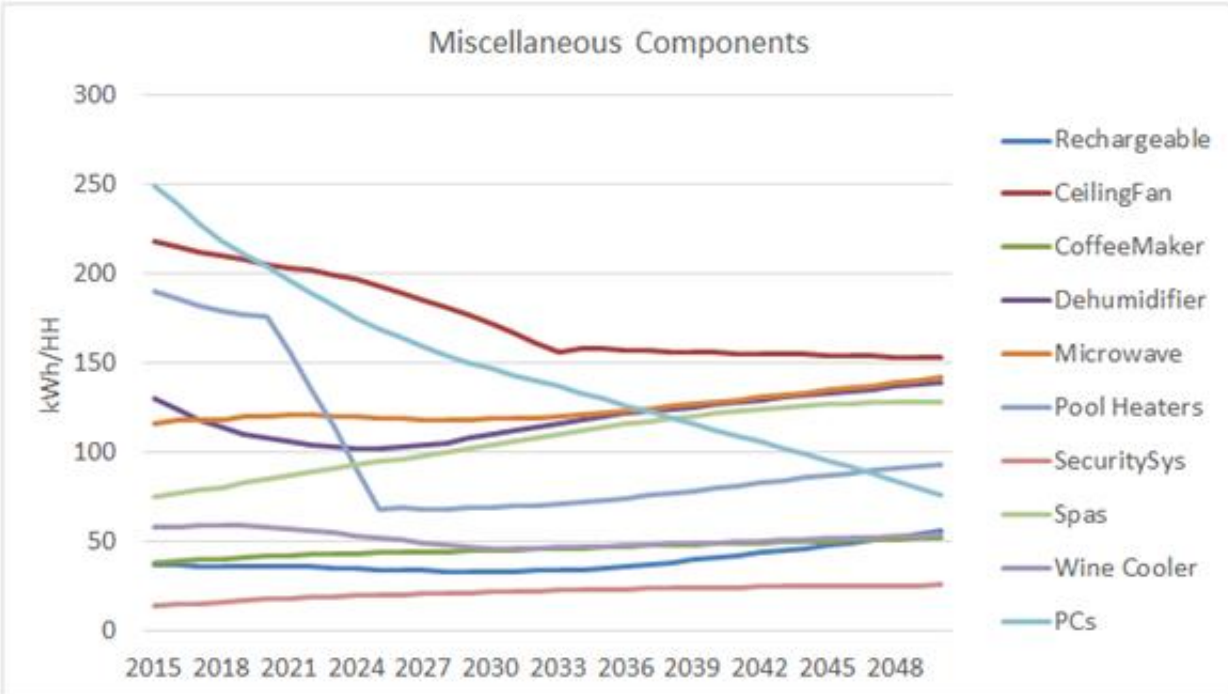


Where 2020 miscellaneous intensity declined 0.4% per year through 2026, the 2021 miscellaneous intensity increases 0.2% per year. Miscellaneous is the only end use showing positive intensity growth, and nearly all this growth is from the Electric Other classification. Specific miscellaneous end uses (Misc_Named) include:

- Rechargeable equipment
- Ceiling fans
- Coffee makers
- Dehumidifiers
- Microwave ovens
- Pool heaters
- Security systems
- Spas
- Wine coolers
- Personal computers and their related peripherals

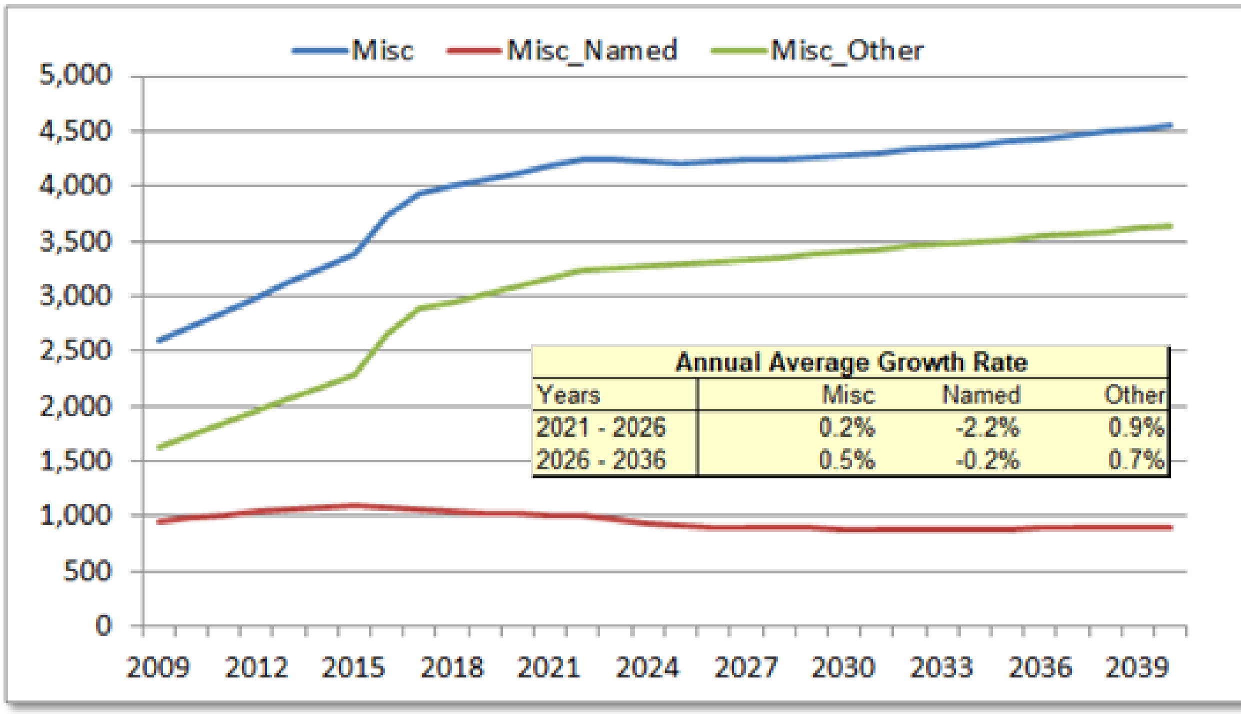
Figure 7 shows intensity projections for these end-uses:

Figure 7: Named Miscellaneous End Uses



The rest of miscellaneous use is classified as Electric Other. This would include plug loads not associated with a specific end use, including electric yard end uses such as lawn mowers, weed trimmers and leaf blowers plus other non-classified household electricity appliances. Depending on the Census Division, Electric Other accounts for two-thirds to three-quarters of Miscellaneous use and is the only end use showing relatively strong intensity growth. Figure 8 shows aggregated Misc_Named and Electric Other (Misc_Other) end-use intensity projections.

Figure 8: Miscellaneous Intensity Trends (kWh/household)



The 2021 SAE spreadsheets include separate intensity projections for total Misc_Named and Misc_Other. One modeling option to consider is to estimate Misc_Other for your own service area by only including Misc_Named in the XOther variable and incorporating a separate trend variable to account for unclassified miscellaneous sales.

Electric Vehicle (EV) and Photovoltaic (PV) Input Spreadsheets

In prior spreadsheets the EV and PV worksheets were populated with generic data and did not include assumptions for calculating use per customer impacts; the worksheets were designed to allow the user to input their own EV and PV assumptions and import the intensities into their residential sales forecast model. This year we updated the EV and PV tabs to include EIA's forecast assumptions from AEO 2021 and include inputs for translating number of units to kWh impact. Figure 9 shows the electric vehicle (EV) worksheet.

Figure 9: EV Worksheet

Year	Households	Vehicles Per HH	Vehicles	Elec Stock Share	Elec Vehicles	AnnualMiles	MilesPerkWh	UEC	Sales	Intensity
2020	18,475,139	2.08	38,476,517	0.6%	223,071	12,000	3.08	3,895	868,907	47.0
2021	18,595,831	2.06	38,302,557	0.7%	253,055	12,000	3.00	3,995	1,011,047	54.4
2022	18,716,069	2.04	38,265,592	0.7%	285,221	12,000	2.95	4,061	1,158,385	61.9
2023	18,832,472	2.03	38,266,490	0.8%	317,951	12,000	2.93	4,097	1,302,487	69.2
2024	18,948,043	2.02	38,324,073	0.9%	352,472	12,000	2.92	4,112	1,449,536	76.5
2025	19,067,257	2.02	38,432,108	1.0%	391,500	12,000	2.91	4,123	1,614,334	84.7
2026	19,185,904	2.01	38,535,465	1.2%	443,427	12,000	2.92	4,114	1,824,201	95.1
2027	19,300,338	2.00	38,598,483	1.3%	499,937	12,000	2.93	4,098	2,048,513	106.1
2028	19,411,864	1.99	38,645,462	1.5%	560,897	12,000	2.94	4,083	2,290,403	118.0
2029	19,521,151	1.98	38,671,258	1.6%	625,184	12,000	2.95	4,072	2,545,819	130.4
2030	19,629,134	1.97	38,681,680	1.8%	694,663	12,000	2.95	4,063	2,822,301	143.8
2031	19,735,350	1.96	38,691,919	2.0%	769,648	12,000	2.96	4,055	3,121,195	158.2
2032	19,840,592	1.95	38,688,564	2.2%	850,650	12,000	2.96	4,050	3,444,768	173.6
2033	19,942,910	1.94	38,691,245	2.4%	938,116	12,000	2.97	4,045	3,794,622	190.3
2034	20,042,312	1.93	38,704,711	2.7%	1,032,268	12,000	2.97	4,041	4,171,581	208.1
2035	20,141,631	1.92	38,717,511	2.9%	1,132,777	12,000	2.97	4,038	4,574,628	227.1
2036	20,238,442	1.91	38,722,361	3.2%	1,239,285	12,000	2.97	4,036	5,002,164	247.2
2037	20,333,673	1.90	38,731,368	3.5%	1,352,300	12,000	2.97	4,035	5,455,879	268.3
2038	20,428,323	1.90	38,745,562	3.8%	1,471,953	12,000	2.98	4,033	5,936,726	290.6
2039	20,522,184	1.89	38,754,018	4.1%	1,596,275	12,000	2.98	4,033	6,437,380	313.7
2040	20,616,078	1.88	38,756,935	4.5%	1,725,293	12,000	2.98	4,033	6,958,312	337.5

The data shown in red are inputs from the EIA's transportation forecast. The values shown in blue are calculations. The calculations are from left to right. The first two columns are census-level of number of households (column B) and average number of vehicles per household (column C). The product gives total number of vehicles (column D). Column E is EIA's EV saturation forecast. Total EVs are the product of total vehicles and expected EV saturation (column F). The other key inputs are expected annual miles driven (column G) and projected kWh per mile (column H). While EV efficiency is expected to improve the average kWh per mile increase as a result total electric or battery electric vehicles (BEV) gaining market share over plug-in hybrid electric vehicles (PHEV). The annual use per car (UEC, column I) is calculated as the annual miles divided by average vehicle efficiency (kWh per mile). Total EV sales (column J) are calculated as the product of EV vehicle stock and vehicle UEC. The EV chagrining intensity is derived by dividing total EV sales by total number of Households (column K). You can add EV to XOther model variable or translate to a monthly EV charging sales and add to your residential average use forecast.

The PV worksheet is shown in Figure 10.

Figure 2: PV Worksheet

Year	PVInstalls	PV Stock	AvgPVSize	PVStockKW	PVDecayRate	AdjPV_KW	CapacityFactor	Generation MWh	OwnUse Share	OwnUse MWh	Excess MWh	OwnUse Intensity
2020	161,737	1,480,572	5.69	8,427,376	0.01	8,353,615	16.3%	11,950,441	80%	9,560,353	2,390,088	(517.5)
2021	168,564	1,649,136	5.78	9,539,898	0.01	9,455,624	16.3%	13,473,487	80%	10,778,789	2,694,697	(579.6)
2022	136,616	1,785,751	5.85	10,455,222	0.01	10,359,823	16.2%	14,666,519	80%	11,733,215	2,933,304	(626.9)
2023	130,108	1,915,859	5.92	11,339,953	0.01	11,235,401	16.1%	15,812,419	80%	12,649,935	3,162,484	(671.7)
2024	126,292	2,042,151	5.97	12,198,741	0.01	12,085,341	16.0%	16,916,846	80%	13,533,477	3,383,369	(714.2)
2025	126,655	2,168,806	6.03	13,072,661	0.01	12,950,674	15.9%	18,046,720	80%	14,437,376	3,609,344	(757.2)
2026	130,489	2,299,295	6.08	13,986,083	0.01	13,855,356	15.9%	19,240,777	80%	15,392,621	3,848,155	(802.3)
2027	130,945	2,430,240	6.13	14,902,700	0.01	14,762,839	15.8%	20,439,922	80%	16,351,938	4,087,984	(847.2)
2028	130,855	2,561,095	6.18	15,831,768	0.01	15,682,741	15.8%	21,660,012	80%	17,328,009	4,332,002	(892.7)
2029	131,441	2,692,536	6.23	16,764,996	0.01	16,606,678	15.7%	22,887,264	80%	18,309,811	4,577,453	(937.9)
2030	133,668	2,826,203	6.27	17,727,400	0.01	17,559,750	15.7%	24,162,616	80%	19,330,093	4,832,523	(984.8)
2031	138,523	2,964,726	6.32	18,724,768	0.01	18,547,494	15.7%	25,495,225	80%	20,396,180	5,099,045	(1,033.5)
2032	140,343	3,105,069	6.36	19,749,272	0.01	19,562,024	15.7%	26,872,751	80%	21,498,200	5,374,550	(1,083.5)
2033	142,981	3,248,050	6.40	20,793,032	0.01	20,595,539	15.7%	28,282,121	80%	22,625,696	5,656,424	(1,134.5)
2034	144,976	3,393,026	6.44	21,865,852	0.01	21,657,922	15.7%	29,740,184	80%	23,792,147	5,948,037	(1,187.1)
2035	147,081	3,540,107	6.48	22,954,248	0.01	22,735,590	15.7%	31,223,908	80%	24,979,127	6,244,782	(1,240.2)
2036	148,160	3,688,266	6.52	24,065,444	0.01	23,835,902	15.7%	32,745,884	80%	26,196,707	6,549,177	(1,294.4)
2037	149,685	3,837,951	6.56	25,188,080	0.01	24,947,426	15.7%	34,287,059	80%	27,429,647	6,857,412	(1,349.0)
2038	150,079	3,988,030	6.60	26,328,676	0.01	26,076,795	15.7%	35,858,452	80%	28,686,761	7,171,690	(1,404.3)
2039	151,399	4,139,429	6.64	27,479,312	0.01	27,216,025	15.7%	37,447,143	80%	29,957,714	7,489,429	(1,459.8)
2040	152,841	4,292,270	6.68	28,656,188	0.01	28,381,395	15.7%	39,079,937	80%	31,263,949	7,815,987	(1,516.5)

The calculations are left to right, starting with the number households (column B) and number of installed systems (column C). EIA inputs are shown in red, the data shown in green illustrates the user-defined inputs and the calculations are shown blue. Total stock (column D) is calculated as the cumulation of number of installed systems (column C). Installed kW capacity (column F) is the product of PV Stock and average PV size (column E). Capacity projection can be adjusted for solar degradation by setting a decay rate (column G); Adjusted kW capacity (column H) is calculated by applying the decay rate to prior year PV capacity estimate. Solar Generation (column J) is derived by applying the capacity factor (column I) to adjusted installed capacity. Total solar generation is split into own-use (that consumed by the customer) and excess (that sold back to the grid). Own-use intensity (column N) is calculated by dividing own-use generation by the number of households. The PV own-use intensity can be imported into your residential forecast file and used to adjust your residential average use forecast.

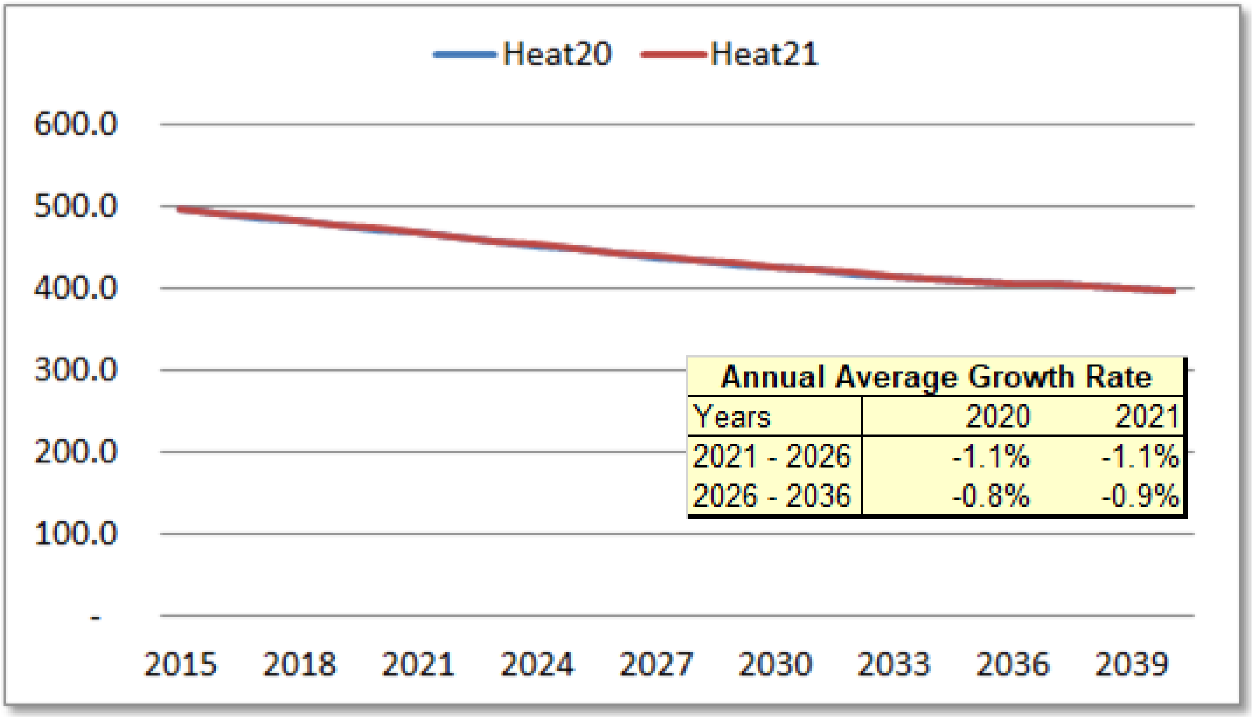
Natural Gas

Space heating and water heating account for 95% of residential natural gas usage, with cooking and clothes dryers accounting for the remainder. At the U.S. level, roughly 50% of households have gas space and water heating. The share of homes with gas space heat has been relatively constant and is expected to increase just slightly over the next 20 years.

Gas Heating

Over the last 10 years, there have been significant improvements in heating system efficiency and housing thermal insulation; these gains are expected to continue over the next thirty years. Given a relatively flat saturation, efficiency improvements drive gas intensity lower. Gas heating intensity starts at a higher usage level because of the calibration into the new 2015 base year, but then declines at a faster rate driven by slightly stronger improvements in gas system efficiency and thermal shell integrity. Figure 11 compares the 2020 and 2021 gas heating intensity projections.

Figure 11: U.S. Gas Heating Intensity (therms/household)

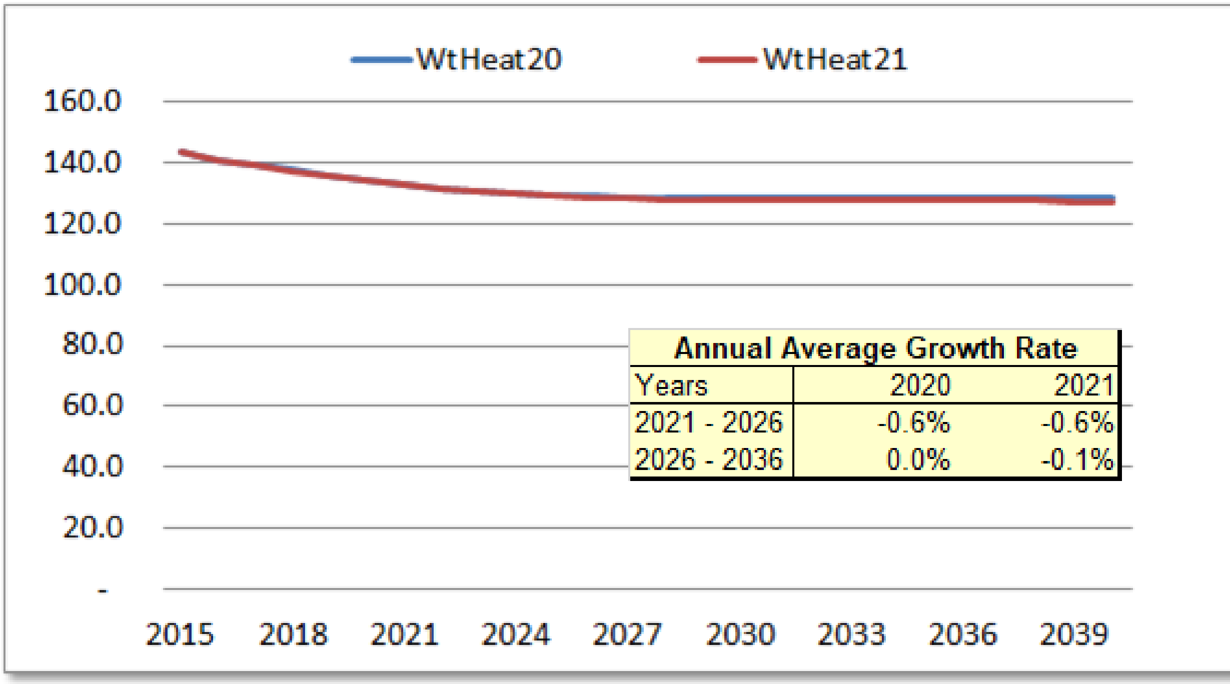


The 2021 natural gas heating projections decline slightly faster than in 2020 forecast in the later part of the forecast period.

Water Heating

Water heating is the second largest gas end use, accounting for approximately 30% of residential natural gas usage. As with furnaces and gas boilers, water heaters have seen significant improvements in energy efficiency. Because efficiency has been increasing while saturation has been flat to declining, gas water heating intensity has also been declining. Figure 12 compares the 2020 and 2021 gas water heating intensity forecasts.

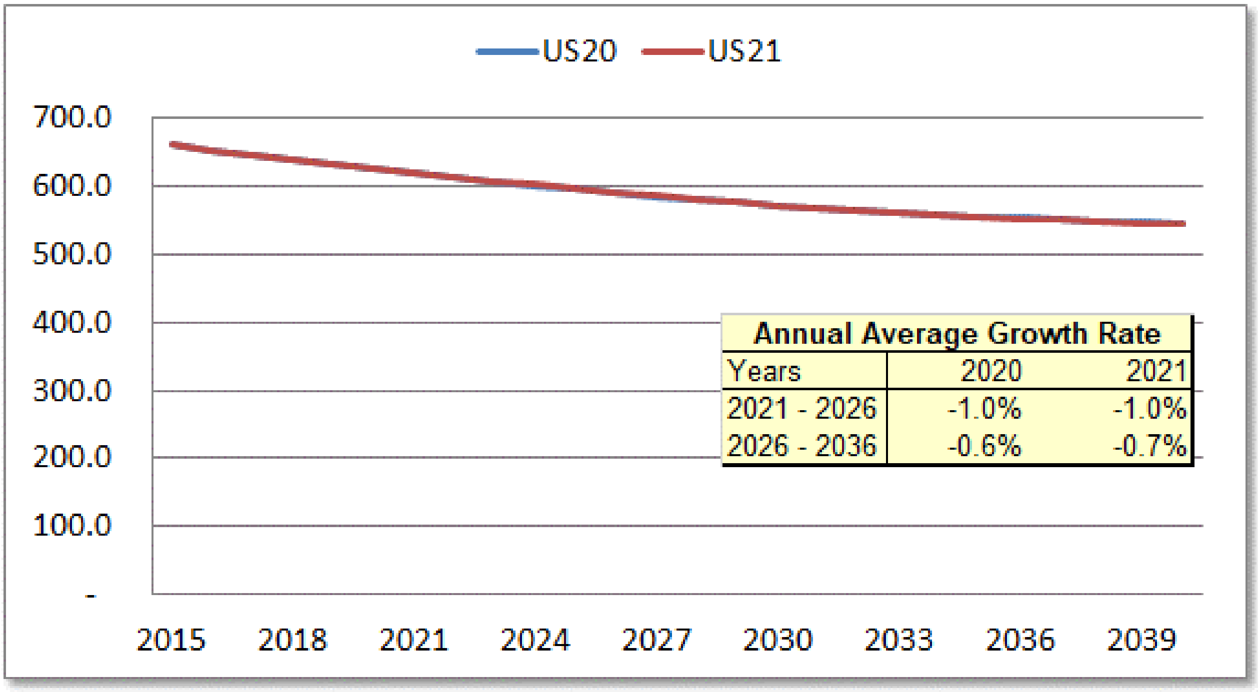
Figure 12: U.S. Gas Water Heating Intensity (therms/household)



The difference in intensities is small. As with heating, the 2021 intensity declines a slightly faster rate between 2026 and 2036.

Gas cooking energy intensities are also projected to decline through the forecast horizon whereas dryer use is expected to increase slightly. When all gas appliances are aggregated, total residential gas intensity averages 1.0% annual decline over the next 5 years and 0.7% thereafter. 2021 gas intensity forecast falls slightly faster than the 2020 forecast after 2026. Figure 13 shows total residential gas intensity forecast.

Figure 13: U.S. Residential Gas Intensity (therms/household)



Annual Average Growth Rate		
Years	2020	2021
2021 - 2026	-1.0%	-1.0%
2026 - 2036	-0.6%	-0.7%

Summary

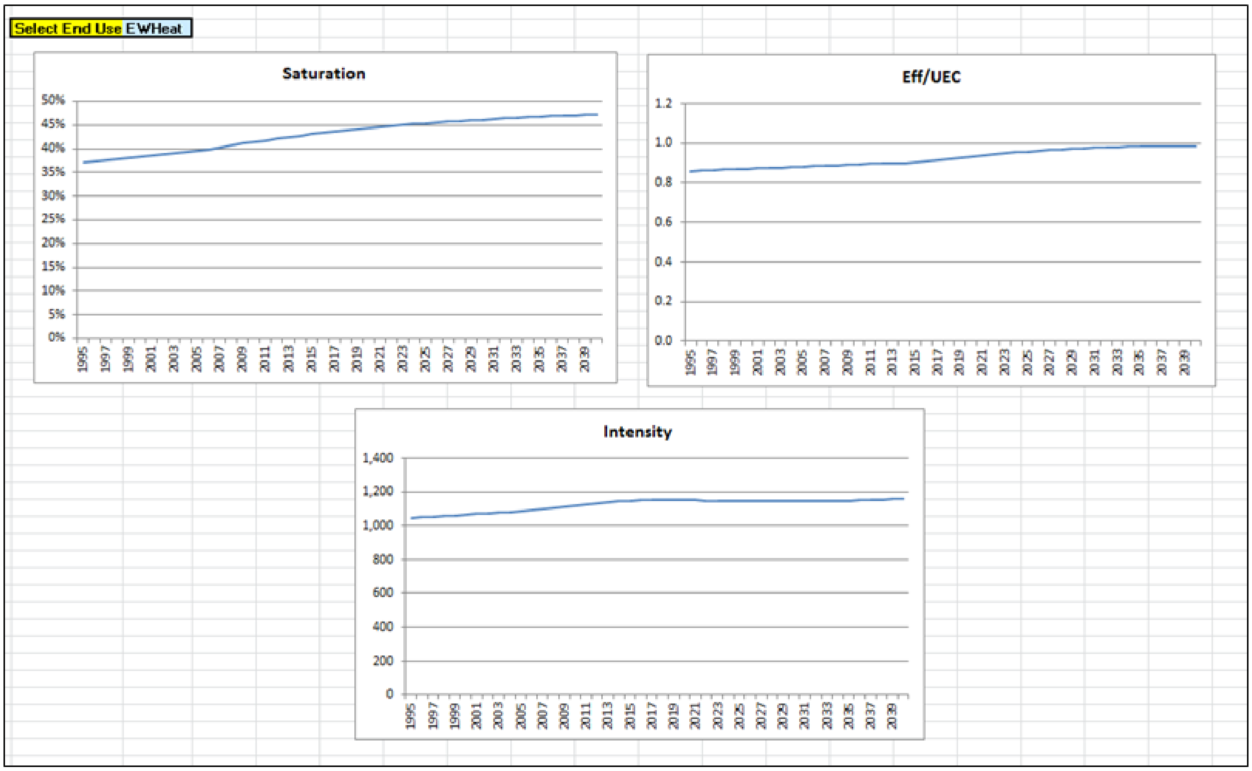
Overall, there is little change in residential electric and natural gas projections from last year's forecast. Miscellaneous usage is still the largest contributor to growth in the residential electric sector. With this in mind, we have separated miscellaneous use for specific end uses from miscellaneous other use.

Appendix A:
Using the SAE Spreadsheets

Updates to the SAE Spreadsheets

Itron continually works to simplify and improve the SAE spreadsheets to allow analysts to view end-use intensity trends, to understand how the indices are calculated, and to customize the SAE inputs (such as end-use saturations and starting UEC) to their own service area. Last year, Itron added a new *Graph* tab that allows the analyst to select an end-use and graph the end-use saturation, efficiency/UEC, and calculated intensity. Figure 14 shows this feature for electric water heaters.

Figure 14: SAE Spreadsheet End-Use Graph - Electric Water Heat



SAE Spreadsheet Organization

The SAE spreadsheets are organized to allow the analyst to calibrate end-use intensities to a specific utility service area organization where service area specific saturation and UEC estimates are available. The spreadsheet tabs include:

- **Definitions** provides descriptive information about end-uses, units and brief descriptions of the other worksheets.
- **EIAData** contains EIA efficiency, consumption, equipment stock, household, floor space and price projections.

- **Calibration** provides base year usage information. It can also be used to customize the spreadsheet to the user's service territory. Figure 15 shows the layout of the Calibration worksheet.

Figure 15: Calibration Worksheet

	A	B	C	D	E	F	G	H	I	J	K
1	Base Year (2009)	EFurn	HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook
2	Consumption (mmBtu)	295,156,965	49,006,093	3,298,852	60,466,462	469,614,726	92,426,664	4,189,994	68,043,412	428,267,637	104,815,834
3	Equipment Stock (units)	29,626,185	9,099,838	699,168	28,312,038	61,707,187	9,099,838	699,168	49,101,682	46,763,693	68,137,629
4	UEC (kWh/unit)	2,920	1,578	1,383	626	2,230	2,977	1,756	406	2,684	451
5	Share (%)	26.0%	8.0%	0.6%	23.4%	54.2%	8.0%	0.6%	43.1%	41.1%	59.9%
6	Raw Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
7	Model-Scaled Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
8											
9	Observed Use Per Customer (kWh/year)	11,909									
10	Adjustment Factor	1.010									
11	Adjusted Intensity (kWh/year)	768	127	9	148	1,222	240	11	177	1,114	273
12											
13	XHeat	1.000									
14	XCool	1.000									
15	XOther	1.000									
16											

Base-year use-per-customer (kWh) for the utility service area is depicted in Row 9 and can be used to calibrate the spreadsheet to the user's service territory. To do this, substitute your weather-normalized average use for the Census Division average-use in Cell B9.

In additional to basic calibration to observed usage, in 2017 we have also added another layer of calibration to better tailor the regional data to utility-specific conditions. In order to get better starting estimates of electric usage by end use, we have utilized MetrixND models to "true up" EIA estimates to the regions. You can do this on the utility level by substituting the adjustment factors in cells B13-15 with estimated coefficients on SAE variables in your residential model. Figure 16 below provides an example.

Figure 16: Model-Based Calibration

	A	B	C	D	E	F	G	H	I	J	K
1	Base Year (2009)	EFurn	HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook
2	Consumption (mmBtu)	295,156,965	49,006,093	3,298,852	60,466,462	469,614,726	92,426,664	4,189,994	68,043,412	428,267,637	104,815,834
3	Equipment Stock (units)	29,626,185	9,099,838	699,168	28,312,038	61,707,187	9,099,838	699,168	49,101,682	46,763,693	68,137,629
4	UEC (kWh/unit)	2,920	1,578	1,383	626	2,230	2,977	1,756	406	2,684	451
5	Share (%)	26.0%	8.0%	0.6%	23.4%	54.2%	8.0%	0.6%	43.1%	41.1%	59.9%
6	Raw Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
7	Model-Scaled Intensity (kWh/year)	1,853	308	21	358	2,389	470	21	346	677	166
8											
9	Observed Use Per Customer (kWh/year)	11,909									
10	Adjustment Factor	0.999									
11	Adjusted Intensity (kWh/year)	1,852	307	21	357	2,387	470	21	346	677	166
12											
13	XHeat	2.438									
14	XCool	1.975									
15	XOther	0.614									
16											

In this case, model-based calibration adjusts heating and cooling starting year usage up based on model coefficients estimated from observed use per customer data. Other usage is adjusted downward.

Resulting end-use intensities are written to the *Intensities* tab. MetrixND project files can link to the *Intensities* tab as the source-data for the constructing of SAE model variables.

StructuralVars

This worksheet contains data about the size of homes and their building shell efficiencies. The results of the calculations on this tab are used in the development of energy intensities for heating and cooling end-uses.

Analysts can substitute local household and floor space estimates for the regional estimates to reflect local conditions in the final energy intensities. Total floor space can be modified in Column E and number of households in Column I.

Shares

The *Shares* tab contains historical saturation estimates and forecasts developed by the EIA. Data from appliance saturation surveys can be used to modify the default saturations. Depending on data availability, these changes can either shift the projections up or down (one survey) or modify the growth rate in the trends (two or more surveys).

Efficiencies

The *Efficiencies* tab provides historical and forecasted end-use efficiency. UEC estimates are used as a proxy for efficiency where specific technology efficiency data (as central air conditioner SEER) are not available. Efficiency trends can also be modified to reflect the utility service area. As a practical matter however, average efficiency for most equipment varies little between regions.

Intensities

Intensities are per-household end-use energy estimate derived from combining end-use saturation, efficiency, and starting UEC. If the user changes saturation and/or efficiency, the changes are reflected in the end-use intensity calculations.

MonthlyMults

The *MonthlyMults* tab provides seasonal multipliers for non-HVAC end-uses. This allows us to accurately gauge seasonal usage for such non weather-sensitive end-uses as water heating, refrigeration and lighting.

Graphs

The *Graphs* tab provides an interface to select an end-use and view historical and projected end-use saturation, efficiency (or UEC where an efficiency measure is not available) and resulting end-use intensity.

EV

Electric vehicle load is added to the base (other) end-use in the SAE model. Input data rows are highlighted in red and include:

- **Households.** Historical and forecasted number of households (column B)
- **EVSold.** Number of EV vehicles sold in any given year (column C)
- **EVDecay.** Number of EV vehicles removed (column D)
- **AnnualMiles.** Annual average miles driven (column G)
- **MilePerKwh.** Average vehicle efficiency (column H)

Additional columns include:

- **EVStock.** Calculated as the sum of all new purchases minus vehicle decay (column E).
- **Share.** The share of households with EVs (column F), calculated as EVStock / Households.
- **UEC.** The Unit Energy Consumption (kWh) for those households that own an EV. Calculated as the number of miles driven divided by the average vehicle miles per kWh (column I).
- **ShareUEC.** Use per household (column K), calculated by multiplying the vehicle UEC and the share of households that own an EV. The resulting annual EV energy intensity is on a kWh per household basis and can be added to the base or other use index in the SAE model.

PV

The SAE spreadsheets also include a worksheet for calculating PV (photovoltaic) energy impacts. Input data rows are highlighted in red and include:

- **Households.** Historical and forecasted Households or customers (column B)
- **PVInstalls.** Number of new PV installations (column C)
- **AvgPVSize.** Average PV kW capacity (column E)
- **PVDecayKW.** PV capacity decay in kW (column G)
- **CapacityFactor.** Capacity Factor (column I)

Additional columns include:

- **PVStockKW.** Estimated PV kW capacity (column H), calculated by summing current and all past PV installed capacity and subtracting the decay, calculated as:

	A	B	C	D	E	F	G	H	I	J	K
1	Base Year (2009)	EFurn	HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook
2	Consumption (mmBtu)	295,156,965	49,006,093	3,298,852	60,466,462	469,614,726	92,426,664	4,189,994	68,043,412	428,267,637	104,815,834
3	Equipment Stock (units)	29,626,185	9,099,838	699,168	28,312,038	61,707,187	9,099,838	699,168	49,101,682	46,763,693	68,137,629
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5	Share (%)	26.0%	8.0%	0.6%	23.4%	54.2%	8.0%	0.6%	43.1%	41.1%	59.9%
6	Raw Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
7	Model-Scaled Intensity (kWh/year)	1,853	308	21	358	2,389	470	21	346	677	166
8											
9	Observed Use Per Customer (kWh/year)	11,909									
10	Adjustment Factor	0.999									
11	Adjusted Intensity (kWh/year)	1,852	307	21	357	2,387	470	21	346	677	166
12											
13	XHeat	2.438									
14	XCool	1.975									
15	XOther	0.614									
16											

- **PVEnergy.** PV MWh (column J) is derived by applying the capacity factor to the PV Capacity Stock, calculated as:

$$(PVStockKW \times 8760 \times CapacityFactor)/1000$$

- **ShareUEC.** Final PV energy intensity (column K) is derived by dividing PVEnergy by total number of households. The estimate is negative, as it represents a load reduction.

Appendix B:
Residential SAE Modeling Framework

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

There are several advantages to this approach.

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

This section describes this approach, the associated supporting SAE spreadsheets, and the MetrixND project files that are used in the implementation. The main source of the residential SAE spreadsheets is the 2020 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

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

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \text{Other}_{y,m} \tag{1}$$

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

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \tag{2}$$

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

Constructing XHeat

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

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

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

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \tag{3}$$

Where:

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

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

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \big/ Eff_{15}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2015 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{15} \times SurfaceArea_{15}} \tag{5}$$

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

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

In Equation 4, 2015 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2015. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2015 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times HeatShare_{15}^{Type} \tag{7}$$

In the SAE spreadsheets, these weights are referred to as Intensities and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2015 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

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

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	916
Electric Space Heating Heat Pump	346

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

Price Impacts. In the 2007 version of the SAE models and thereafter, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a 10-year horizon. To introduce price effects, the Heat Index as defined by Equation 4 above is multiplied by a 10-year moving-average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \middle/ Eff_{15}^{Type} \right)} \times \left(TenYearMovingAverageElectric\,\mathrm{Pr}\,i\,ce_{y,m}\right)^{\varphi} \times \left(TenYearMovingAverageGas\,\mathrm{Pr}\,i\,ce_{y,m}\right)^{\gamma} \tag{8}$$

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

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

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{15}}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.20} \times \left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{15,7}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{15,7}}\right)^{\kappa} \qquad (9)$$

Where:

- $WgtHDD$ is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- HDD is the annual heating degree days for 2015
- $HHSize$ is average household size in a year (y)
- $Income$ is average real income per household in year (y)
- $ElecPrice$ is the average real price of electricity in month (m) and year (y)
- $GasPrice$ is the average real price of natural gas in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2015). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

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

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

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

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \qquad (10)$$

Where

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

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

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type} \right)}{\left(Sat_{15}^{Type} \middle/ Eff_{15}^{Type} \right)} \qquad (11)$$

Data values in 2015 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2015. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2015 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{15}^{Type}}{HH_{15}} \times CoolShare_{15}^{Type} \qquad (12)$$

In the SAE spreadsheets, these weights are referred to as Intensities and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2015 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

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

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,012
Space Cooling Heat Pump	306
Room Air Conditioning	277

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

Price Impacts. In the 2007 SAE models and thereafter, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities.

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \middle/ Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} \middle/ Eff_{15}^{Type}\right)} \times$$
$$\left(TenYearMovingAverageElectric\,Price_{y,m}\right)^{\varphi} \times \left(TenYearMovingAverageGas\,Price_{y,m}\right)^{\gamma} \quad (13)$$

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

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

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{15}}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.20} \times$$
$$\left(\frac{Elec\,Price_{y,m}}{Elec\,Price_{15}}\right)^{\lambda} \times \left(\frac{Gas\,Price_{y,m}}{Gas\,Price_{15}}\right)^{\kappa} \quad (14)$$

Where:

- $WgtCDD$ is the weighted number of cooling degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- CDD is the annual cooling degree days for 2015.

By construction, the $CoolUse$ variable has an annual sum that is close to 1.0 in the base year (2015). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

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

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

The explanatory variable for other uses is defined as follows:

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

The first term on the right-hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term ($OtherUse$) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

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

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{15}^{Type} \Big/ \frac{1}{UEC_{15}^{Type}} \right)} \times MoMult_m^{Type} \times$$
$$(TenYearMovingAverageElectric\ Pr\,i\,ce)^{\lambda} \times$$
$$(TenYearMovingAverageGas\ Pr\,i\,ce)^{\kappa} \tag{16}$$

Where:

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

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

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

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

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_y}{HHSize_{15}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{15}}\right)^{0.10} \times$$
$$\left(\frac{Elec\ Pr\,ice_{y,m}}{Elec\ Pr\,ice_{15}}\right)^{\varphi} \times \left(\frac{Gas\ Pr\,ice_{y,m}}{Gas\ Pr\,ice_{15}}\right)^{\lambda} \tag{17}$$

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

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

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 17. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3 and are now in xlsx Excel file format.

Figure 17: Mapping of States to Census Divisions

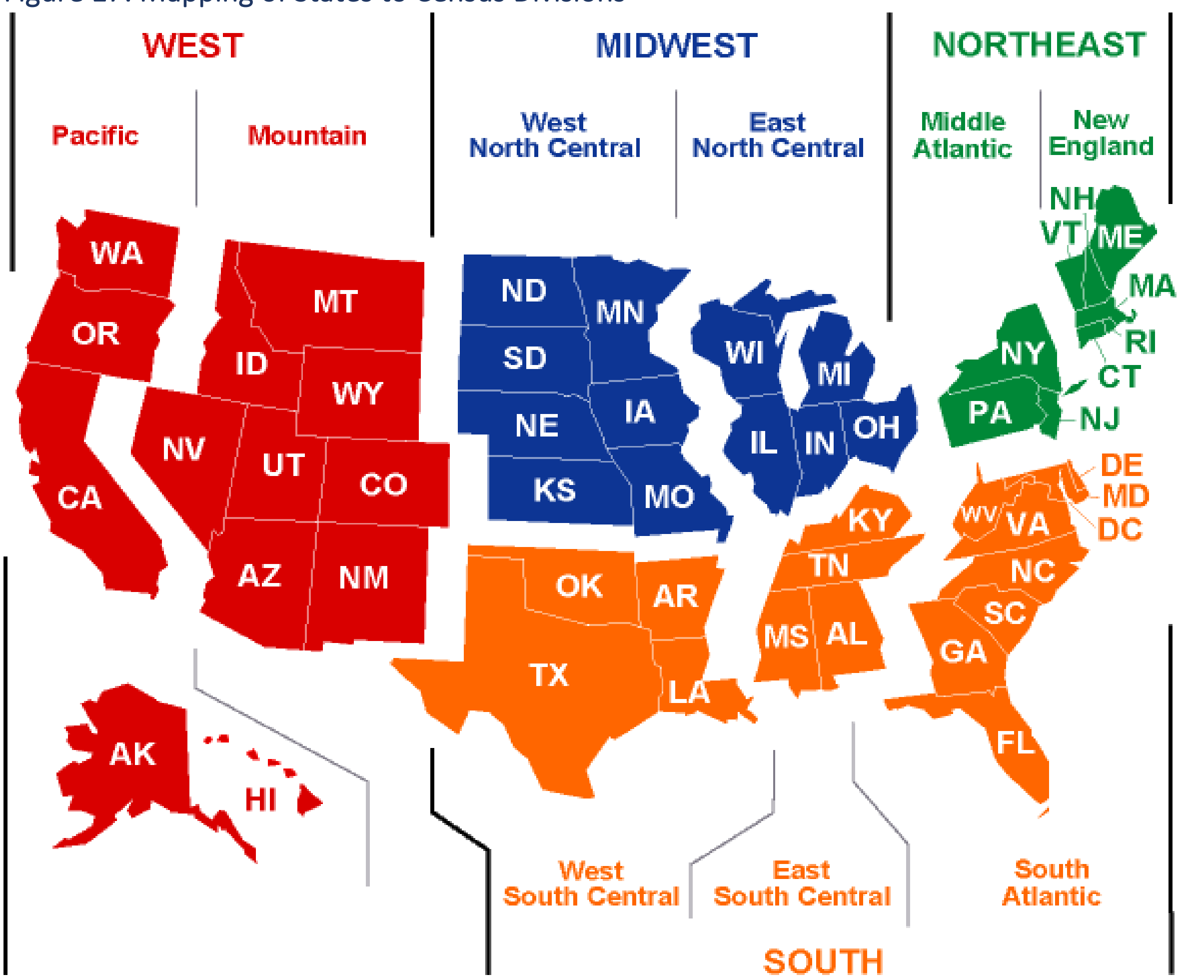

Table 3: List of SAE Files

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

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

Each of the nine SAE spreadsheets contains the following tabs:

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

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

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the Usage variables for each end-use. There are five types of elasticities included on this table.
    - Economic variable elasticities
    - Short-term own price elasticities
    - Short-term cross price elasticities
    - Long-term own price elasticities
    - Long-term cross price elasticities

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

Data Tables

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

Transformation Tables

- **EconTrans** computes the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans** computes the HDD and CDD indices used in the usage equations.
- **ResidentialVars** computes the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars** computes the calendar binary variables that could be required in the regression model.
- **AnnualFcst** computes the annual historical and forecast sales and annual change in sales.
- **EndUseFcst** computes the monthly sales forecasts by end uses.

Models

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

Steps to Customize the Files for Your Service Territory

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

Minimum Customization

- Save the MetrixND project file and the spreadsheet into the same folder
- Select the spreadsheet and MetrixND project file from the appropriate Census Division
- Open the spreadsheet and navigate to the *Calibration* tab
- In cell "B9", replace base year Census Division use-per-customer with observed use-per-customer for your service territory
- Save the spreadsheet and open the MetrixND project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Further Customization of Starting Usage Levels

In addition to the minimum steps listed above, you can also utilize model-based calibration process described previously to further fine-tune starting year usage estimates to your service territory.

Customizing the End-use Share Paths

You can also install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region. Make sure that base year shares on the *Calibration* tab reflect changes on the *Shares* tab.

Customizing the End-use Efficiency Paths

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

DATA REQUEST

KPSC 1_60 Refer to the IRP, Volume A, Exhibit H, page 986. Provide the supporting material, if any, and explain how each of the four heating degree days (HDD) variables were derived.

RESPONSE

KPCO_R_KPSC_1_60_Attachment1 contains supporting material for computing the four heating degree day variables.

Heating Degree Days are based on the following formula:

Maximum of ((Base Degrees less Average Daily Temperature) or 0). This amount is calculated daily and aggregated for the month. The four heating degree variables are based on different base degree temperatures and day types.

HDD50-Heating Degree Days based on 50 Degrees F

HDD55-Heating Degree Days based on 55 Degrees F

HDD65-Heating Degree Days based on 65 Degrees F

HDD65WkEnd-Heating Degree Days based on 65 Degrees F

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_61 Refer to the IRP, Volume A, Exhibit H, page 986. Explain the meaning of and how the Summer Fuzzy-Summer Days variable and the Winter Fuzzy-Winter Days variable were derived.

RESPONSE

The SummerFuzzy and WinterFuzzy variables are binary variables that attempt to capture the seasonal calendar impact on peak demand. The SummerFuzzy variable encompasses the full summer months (June, July, August, and September), along with the partial months of May and October. It ramps up to the Summer and ramps down to the Fall. The WinterFuzzy variable encompasses the full winter months (December, January, February, and March), along with the partial months of November and April. These variables help measure transitional behavior that occurs between the cooling and heating seasons.

SummerFuzzy = (Day>=15) * (MonthlyBinary.May) * (Day-15)/16 + MonthlyBinary.June + MonthlyBinary.July + MonthlyBinary.August + MonthlyBinary.September + (Day<=15) * (MonthlyBinary.October) * (16-Day)/16

WinterFuzzy = (Day<=15) * (MonthlyBinary.November) * (Day/16) + MonthlyBinary.November * (Day>15) + MonthlyBinary.December + MonthlyBinary.January + MonthlyBinary.February + MonthlyBinary.March + (Day<=15) * MonthlyBinary.April * (16-Day)/16

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_62 Refer to the IRP, Volume A, Exhibit H, pages 989 and 993. Explain the purpose and customer behavioral significance of including the HLight-Hours of Sunlight and DST-Daylight Savings Time variables in the summer and winter peak demand forecast equations.

RESPONSE

The purpose for including the HLight-Hours of Sunlight and DST-Daylight Savings Time variables in the peak demand model is derived from the fact that peak demand is dependent on customer behavior throughout the day based on simultaneous elements of usage. A primary driver of demand is lighting. The Sunlight and Daylight Savings Time variables are used to help measure this usage. Lighting usage is heavily influenced by the amount of sunlight available throughout the day. Daylight Savings results in subtle hourly demand changes.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_63 Refer to the IRP, Volume A, Exhibit H, page 989.
a. Explain the rationale for including all four cooling degree days (CDD) variables in the Residential Cooling Peak Demand model to forecast summer peak demand.
b. Explain whether the data contained in the CDD65WkEnd and CDD70WkEnd variables are included in the CDD65 and CDD70 variables.
c. Explain why there are not multicollinearity problems between the variables.

RESPONSE

a. Peak demand is typically recorded on an hourly basis, resulting in a shape throughout the day. The four CDD variables measure the varying influence of temperature on demand during the day. It measures the segments of demand into temperature and non-temperature related loads.

b. Yes. The CDD65 and CDD70 variables refer to all days. The CDD65WkEnd and CDD70WkEnd variables refer to weekends only.

c. Multicollinearity is not considered a problem for prediction or forecasting, but only an issue for inference among explanatory variables. The trade-off between some level of multicollinearity and forecast accuracy is worthwhile. The variables used in this model are used to forecast end use demand. Many of these variables are used to capture both subtle differences and unique aspects of the load and temperature relationship.

Witness: Glenn R. Newman

DATA REQUEST

KPSC 1_64 Refer to the IRP, Volume A, Exhibit H, page 989. Explain what information is inherent in the WinterFuzzy variable that contributes to forecasting summer peak demand.

RESPONSE

The WinterFuzzy binary variable (also described in the Company's responses to KPSC-1-61 & 64) is used primarily for the winter months and is relevant for a residential heating peak demand model. As the calendar transitions from Winter to Summer in May and then transitions from Summer to Winter in October, there are certain days when the temperatures could result in residential heating. When this occurs, the load is captured by the SummerFuzzy binary variable. The negative coefficient reflects the isolation of these transition days - indicative of consumers being less inclined to heat during this period. When the calendar moves exclusively to the summer months, the binary variable SummerFuzzy effectively becomes 0, or irrelevant to the residential heating peak demand model.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_65 Refer to the IRP, Volume A, Exhibit H, page 993.
a. Explain the rationale for including all four HDD variables in the Residential Heating Peak Demand model to forecast winter peak demand.
b. Explain the meaning of the negative coefficient sign of the HDD 55 and the HDD65WkEnd variables.
c. Explain why there are not multicollinearity problems between the four HDD variables.

RESPONSE

a. Peak demand is typically recorded on an hourly basis, resulting in a shape throughout the day. The four HDD variables measure the varying influence of temperature on demand during the day. It measures the segments of demand into temperature and non-temperature related loads.

b. The HDD55 represents the segment of demand where the load is not influenced by temperature. This is referred to as base load, where the change in demand can be very flat. The coefficient sign can fluctuate. The HDD65WkEnd is a binary variable indicating the load impact on the weekends. Loads tend to be lower on the weekends due to decreasing demand from the commercial and industrial sectors. Therefore, this negative coefficient helps to capture this reduction in the model.

c. Multicollinearity is not considered a problem for prediction or forecasting, but only an issue for inference among explanatory variables. The trade-off between some level of multicollinearity and forecast accuracy is worthwhile. The variables used in this model are used to forecast end use demand. Many of these variables are used to capture both subtle differences and unique aspects of the load and temperature relationship.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_66 Refer to the IRP, Volume A, Exhibit H, page 993. Explain the rationale for including both the SummerFuzzy and WinterFuzzy variables in the model and the meaning of the SummerFuzzy negative coefficient.

RESPONSE

The WinterFuzzy binary variable (also described in the Company's responses to KPSC-1-61 & 64) is used primarily for the winter months and is relevant for a residential heating peak demand model. As the calendar transitions from Winter to Summer in May and then transitions from Summer to Winter in October, there are certain days when the temperatures could result in residential heating. When this occurs, the load is captured by the SummerFuzzy binary variable. The negative coefficient reflects the isolation of these transition days - indicative of consumers being less inclined to heat during this period. When the calendar moves exclusively to the summer months, the binary variable SummerFuzzy effectively becomes 0, or irrelevant to the residential heating peak demand model.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_67 Refer to the IRP, Volume A, Exhibit H, page 1004. Explain Other Residential Peak Demand and the rationale for including four CDD and four HDD variables in the forecast equation.
a. Explain the rationale for including the WinterFuzzy variable in the Commercial Cooling Peak Demand model and the meaning of the coefficient's negative sign.
b. Explain why there are not multicollinearity issues between the CDD variables.

RESPONSE

The Other Residential Peak Demand model estimates the consumer demand that is not directly related to temperature. This is often referred to as base demand, when the usage depends primarily non-temperature related factors (refrigeration, lighting, etc.) The CDD and HDD variables are included to capture any limited amount of temperature dependent relationships.

a. The WinterFuzzy variable is binary and encompasses the full winter months (December, January, February, and March), along with the partial months of November and April. Sometimes, these months contain high temperatures that result in Cooling Degree Days. When this happens, it will use the coefficient associated with the WinterFuzzy variable. When the calendar moves to the summer months, the binary variable WinterFuzzy effectively becomes 0, or irrelevant to the model. If the WinterFuzzy is relevant to the model, the negative coefficient is due to the shoulder months (November & April) when the overall demand is low and the correlation to temperature is lower. See also the Company's responses to KPSC-1-61,64 and 66.

b. Multicollinearity is not considered a problem for prediction or forecasting, but only an issue for inference among explanatory variables. The trade-off between some level of multicollinearity and forecast accuracy is worthwhile. The variables used in this model are used to forecast end use demand. Many of these variables are used to capture both subtle differences and unique aspects of the load and temperature relationship.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_68 Refer to the IRP, Volume A, Exhibit H, page 1018.
a. Explain the meaning of the negative HDD 55 coefficient.
b. If not answered previously, explain the rationale for including the SummerFuzzy and WinterFuzzy variables in the Commercial Peak Demand Heating model and the meaning of the coefficient's negative sign.
c. Explain why there are not multicollinearity issues between the HDD variables.

RESPONSE

a. The HDD55 represents the segment of demand where the load is not influenced by temperature. This is referred to as base load, where the change in demand can be very flat. The coefficient sign can fluctuate.

b. The WinterFuzzy binary variable is used primarily for the winter months and is relevant for a commercial heating peak demand model. Similarly, the SummerFuzzy variable is binary and encompasses the full summer months (June, July, August, and Spetember), along with the partial months of May and October. Sometimes, these months contain lower temperatures that result in Heating Degree Days. When this happens, it will use the coefficient associated with the SummerFuzzy variable. When the calendar moves to the winter months, the binary variable SummerFuzzy effectively becomes 0, or irrelevant to the model. The SummerFuzzy coefficient is much smaller than the WinterFuzzy coefficient but it is positive. See also the Company's responses to KPSC-1-61,64,66 and 67.

c. Multicollinearity is not considered a problem for prediction or forecasting, but only an issue for inference among explanatory variables. The trade-off between some level of multicollinearity and forecast accuracy is worthwhile. The variables used in this model are used to forecast end use demand. Many of these variables are used to capture both subtle differences and unique aspects of the load and temperature relationship.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_69 Refer to the IRP, Volume A, Exhibit H, page 1032.
a. Explain the rationale for including four CDD and four HDD variables in the forecast equation.
b. Explain the meaning of the negative coefficient signs.

RESPONSE

a. Industrial load is not typically influenced by temperature. The CDD and HDD variables are primarily included here for consistency purposes with the other end use models and to act as a proxy for any other seasonal-related variability.

b. The negative coefficient sign indicates there is little to no correlation between industrial load and temperature. These coefficients can fluctuate and are largely insignificant in the forecast model. However, a negative coefficient indicates that a particular hour (on average) is lower relative to the others conditional on the level of seasonal-related variability as measured by the various degree-day variables.

Witness: Glenn R. Newman

Kentucky Power Company
KPSC Case No. 2023-00092
Staff's First Set of Data Requests
Dated May 22, 2023

DATA REQUEST

KPSC 1_70 Refer to the IRP, Volume A, Exhibit H, page 1032. Refer also to IRP, Volume A, Exhibit H, pages 1038-1039. Explain why variables that look to be insignificant are left in the forecast equation.

RESPONSE

Industrial demand is not typically influenced by temperature. However, there is volatility in the load throughout the year driven by economic and operational dynamics. It is important to maintain some level of variation in this sector because it contributes to the cumulative variation in system demand. The temperature variables in this model are used as a volatility proxy rather than a primary driver of demand. Yet, these variables also have a side benefit of maintaining uniformity with the other revenue class models as they are all aggregated together to reflect the total system demand.

Witness: Glenn R. Newman

VERIFICATION

The undersigned, Kamran Ali, being duly sworn, deposes and says he is the Vice President of Transmission Planning and Analysis 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.

KamranAli

State of Ohio)
) Case No. 2023-00092
County of Franklin)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Kamran Ali, on June 8th 2023

BRITTANY HENRY - NOTARY PUBLIC
MY COMMISSION EXPIRES 09/07/25
STATE OF OHIO

Notary Public

My Commission Expires 09 07 25

Notary ID Number 2020- RE - 819525

Haratym Verification Form.doc

DocVerify ID:	CB297779-5DB4-4ADA-8EDD-A93C4E6E531A
Created:	June 13, 2023 04:55:51 -8:00
Pages:	1
Remote Notary:	Yes / State: KY

E-Signature Summary

E-Signature 1: Tomasz Haratym (TH)
June 13, 2023 06:35:32 -8:00 [3CF9324F0EF6] [99.254.91.240]
tharatym@crai.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 13, 2023 06:35:32 -8:00 [599EDD091FE2] [167.239.221.104]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Tomasz J. Haratym, being duly sworn, deposes and says he is the Associate Principal, for Charles River Associates, 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.

Tomasz Haratym 3CF9324F0EF6
Signed on 2023/06/13 06:35:32 -8:00

Tomasz J. Haratym

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Tomasz J. Haratym, on ____June 13, 2023_________.

599EDD091FE2
Signed on 2023/06/13 06:35:32 -8:00

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025
Notary Stamp 2023/06/13 06:35:32 PST 599EDD091FE2

Notarial act performed by audio-visual communication

My Commission Expires ____06/21/2025_____________

Notary ID Number ____KYNP31964________________

Newman Verification Form rev1.doc

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Created:	June 14, 2023 04:56:14 -8:00
Pages:	1
Remote Notary:	Yes / State: KY

E-Signature Summary

E-Signature 1: Glenn Newman (GN)
June 14, 2023 08:38:19 -8:00 [F27763056967] [167.239.221.105]
rnewman@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 14, 2023 08:38:19 -8:00 [5076D00D8147] [167.239.221.107]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Glenn R. Newman, being duly sworn, deposes and says he is the Manager of Economic Forecasting 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.

Glenn Newman
Signed on 2023/06/14 08:38:19 -8:00

Glenn R. Newman

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Glenn R. Newman, on _____June 14, 2023___________.

Signed on 2023/06/14 08:38:19 -8:00

Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025
Notary Stamp 2023/06/14 08:38:19 PST 5076D00D8147

Notarial act performed by audio-visual communication

My Commission Expires _____06/21/2025____________

Notary ID Number ____KYNP31964_________________

Soller Verification Form rev1.doc

DocVerify ID:	7DAF9A38-B50A-4A15-B9D9-248EBF121104
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E-Signature Summary

E-Signature 1: Gregory Jerome Soller (GJS)
June 16, 2023 08:36:37 -8:00 [D48C371F47DA] [167.239.221.106]
gsoller@aep.com (Principal) (Personally Known)

E-Signature Notary: Jennifer Young (JAY)
June 16, 2023 08:36:37 -8:00 [84969C7E5A20] [167.239.221.105]
jayoung1@aep.com
I, Jennifer Young, did witness the participants named above electronically sign this document.

VERIFICATION

The undersigned, Gregory J. Soller, being duly sworn, deposes and says he is the Resource Planning Manager 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.

Gregory Jerome Soller
Signed on 2023/06/16 08:36:37 -8:00

____
Gregory J. Soller

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Gregory J. Soller, on _____June 16, 2023________.

Signed on 2023/06/16 08:36:37 -8:00

____
Notary Public

JENNIFER A. YOUNG
ONLINE NOTARY PUBLIC
STATE AT LARGE KENTUCKY
Commission # KYNP31964
My Commission Expires Jun 21, 2025
Notary Stamp 2023/06/16 08:36:37 PST 84969C7E5A20

Notarial act performed by audio-visual communication

My Commission Expires ______06/21/25_____________

Notary ID Number ____KYNP31964________________

VERIFICATION

The undersigned, Brian K. West, being duly sworn, deposes and says he is the Vice President, Regulatory & Finance for Kentucky Power, 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.

Brian K. West

Commonwealth of Kentucky)
) Case No. 2023-00092
County of Boyd)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Brian K. West, on June 15, 2023.

Scott E. Bishop
Notary Public

SCOTT E. BISHOP
Notary Public
Commonwealth of Kentucky
Commission Number KYNP32110
My Commission Expires Jun 24, 2025

My Commission Expires June 24, 2025

Notary ID Number KYNP 32110