COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC 2021 JOINT INTEGRATED	**)**	
RESOURCE PLAN OF LOUISVILLE GAS AND	**)**	**CASE NO. 2021-00393**
ELECTRIC COMPANY AND KENTUCKY	**)**	
UTILITIES COMPANY	**)**	

RESPONSE OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY TO JOINT INTERVENORS INITIAL REQUESTS FOR INFORMATION DATED JANUARY 21, 2022

FILED: FEBRUARY 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Daniel K. Arbough**, being duly sworn, deposes and says that he is Treasurer for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Daniel K. Arbough

Daniel K. Arbough

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of February 2022.

Judy Schooler

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)

COUNTY OF JEFFERSON)

The undersigned, **Christopher D. Balmer**, being duly sworn, deposes and says that he is Director – Transmission Strategy and Planning for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Christopher D. Balmer

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of February 2022.

Judy Schroder
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **John Bevington**, being duly sworn, deposes and says that he is Director – Business and Economic Development for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

John E. Bevington
John Bevington

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of February 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Philip A. Imber**, being duly sworn, deposes and says that he is Director – Environmental and Federal Regulatory Compliance for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Philip A. Imber

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of February 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Eileen L. Saunders**, being duly sworn, deposes and says that she is Vice President, Customer Services for Louisville Gas and Electric Company and Kentucky Utilities Company and an employee of LG&E and KU Services Company, and that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge, and belief.

Eileen L Saunders

Eileen L. Saunders

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of February 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Power Supply for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State this 8th day of February 2022.

Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **David S. Sinclair**, being duly sworn, deposes and says that he is Vice President, Energy Supply and Analysis for Kentucky Utilities Company and Louisville Gas and Electric Company and an employee of LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

David S. Sinclair

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of February 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

VERIFICATION

COMMONWEALTH OF KENTUCKY)
)
COUNTY OF JEFFERSON)

The undersigned, **Stuart A. Wilson**, being duly sworn, deposes and says that he is Director, Energy Planning, Analysis & Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

Stuart A. Wilson

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 10th day of February 2022.

Judy Schooler
Notary Public

Notary Public ID No. 603967

My Commission Expires:

July 11, 2022

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.1

Responding Witness: Stuart A. Wilson

Q-1.1. The National Standard Practice Manual for Benefit-Cost Analysis of Distributed Energy Resources ("NSPM-DER," available at https://www.nationalenergyscreeningproject.org/national-standard-practicemanual/) provides a comprehensive framework for cost- effectiveness assessment of distributed energy resources including distributed generation, distributed storage, demand response, and energy efficiency. The NSPM-DER also provides guidance on addressing multiple DERs and rate impacts and cost shifts. In their order in the Kentucky Power Company Case No. 2020-00174, concerning net metering, the Commission adopted a series of principles to be used when establishing new net metering rates. These principles are consistent with those presented in the NSPM-DER and are applicable to evaluating the benefits and costs of all DER's, in addition to net metering.

a. Is the Company aware of and familiar with the NSPM-DER?

b. Has the Company utilized the NSPM-DER within the IRP process for evaluating DSM, energy efficiency, and distributed generation resources?

A-1.1.

a. Yes. The Companies are aware of this document.

b. No.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.2

Responding Witness: John Bevington / Stuart A. Wilson

Q-1.2. These questions pertain to the impacts of the IRP on residential customers with low- and fixed-incomes.

a. Please provide any and all internal analysis and discussion materials used to forecast and consider the impact of the proposed IRP on low- income customers at 30%, 50%, and 80% Area Median Income (AMI).

b. Please provide any historical data on low-income households considered in the preparation of the IRP by census tract and zip code.

c. Please provide any internal analysis of Annual Use-per-Customer and Total Energy Sales correlated to impact on average customer bills as 30%, 50%, and 80% Area Median Income (AMI). Please provide data by census tract and zip code if possible.

d. Please provide any analysis conducted on residential end-use trends and the impact on low-income customers at 30%, 50%, and 80% Area Median Income (AMI) by census tract and zip code. Please provide any analysis conducted on residential end-use trends and the impact on low-income customers at 30%, 50%, and 80% Area Median Income (AMI) by census tract and zip code.

e. Please explain how the Companies propose to create equitable models for collecting survey data and direct feedback for residential, small customers as is repeatedly mentioned in regard to large, nonresidential, commercial customers.

f. Please provide any analysis performed by the Companies specific to future low-income household customer demand for energy.

g. Please provide any analysis conducted on how "expected increases in the cost of generation"[1] will impact low-income households? How will this impact households at 30%, 50%, and 80% Area Media Income (AMI)? Provide the data by census tract and zip code.

h. Please provide any analysis on the impact of the Integrated Resource Plan (IRP) on the Low-Income Weatherization Program (WeCare).

i. Please provide any and all internal analysis and any discussion materials pertaining to the long-term planning and implementation of the WeCare program for the period covered by the proposed Integrated Resource Plan (IRP).

j. Please explain why the Company projects no further customer energy savings via the WeCare program after 2025 (as shown in Table 8-12, p.96 of pdf, 2021 IRP Volume I.)

k. Please provide any analysis performed by the Companies of the impact on low-income customers of the effective termination of the WeCare program after 2025.

l. Please provide any analysis and discussion materials from this IRP process pertaining to the planning and development of new DSM programs targeted at low-income households at 30%, 50%, and 80% Area Median Income (AMI). Please provide any data considered as a part of that analysis and discussions by census tract and zip code.

m. Please provide any analysis of the impact of the preferred portfolio of resources on low-income customers, and of how those concerns were considered as part of the Integrated Resource Plan (IRP) process.

n. Please provide any studies related to environmental and health impacts on low-income communities and communities of color considered as a part of the Integrated Resource Plan (IRP) process. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

o. Please provide any and all studies related to the impact of economic

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[1] Case No. 2021-00393 (Ky. PSC January 11, 2022), Electronic 2021 Joint Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company, Order (in which the Commission granted Joint Intervenor statues to Metropolitan Housing Coalition (MHC), Kentuckians for the Commonwealth (KFTC), Kentucky Solar Energy Society (KYSES), and Mountain Association (MA) (collectively, Joint Intervenors), 4.

disparities on low-income communities and communities of color considered as a part of the Integrated Resource Plan (IRP) process. Please provide any and all internal analysis and discussion materials from the Companies of these studies.

A-1.2. The Companies objective is to provide all customers, irrespective of income or other demographic criteria, with safe and reliable service at the lowest reasonable cost. The Companies' IRP reflects this objective.

a. The Companies did not perform such analysis. Additionally, the Companies do not have access to customer-specific income data.

b. The Companies did not consider this in the preparation of the IRP.

c. The Companies have not performed this analysis.

d. The Companies have not performed this analysis.

e. See the response to PSC 1-31.

f. The Companies have not performed this analysis.

g. The Companies have not performed this analysis.

h. See the response to PSC 1-4a.

i. Long-term planning and analysis related to the WeCare program can be found in Case No. 2017-00441 Exhibit GSL-1, Section 2.1.[2]

j. The Companies currently have Commission approval to continue the program through the end of 2025 and expect to apply to continue the program beyond this date.

k. The Companies have not performed this analysis. See the response to part (j).

l. See the response to PSC 1-4a.

m. The Companies have not performed this analysis.

n. The Companies have not performed this analysis.

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[2] Available at: https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

o. The Companies have not performed this analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.3

Responding Witness: Stuart A. Wilson

Q-1.3. Produce any workpapers (in machine readable and unprotected format, with formulas intact) used to produce the load forecast, the reserve margin analysis, the long-term resource planning analysis (including Table 20 of the same), and the RTO membership analysis.

A-1.3. The Companies are providing the non-confidential portion of their response via a file transfer site, for which the Companies are filing a motion to deviate from 807 KAR 5:001 § 8(3). The non-confidential portion of this response is available at https://highq.in/h17yfxqx5f.

Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential information.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.4

Responding Witness: Stuart A. Wilson

Q-1.4. Please refer to page 5-15 of the IRP where it says: "For each energy requirements and fuel price case, the Plexos model from Energy Exemplar was used to identify the least-cost generation portfolio for serving customers at the end of the IRP planning period. The analysis considered all costs for new and existing resources, and it optimized the portfolio to minimize energy and new capacity costs. An annual resource plan was then developed for each case to meet minimum reserve margin requirements (i.e., 17 percent in the summer and 26 percent in the winter) throughout the planning period. To assess the potential for new DSM programs, the PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base energy requirements, base fuel case."

a. Please confirm that the Companies used Plexos to perform capacity expansion modeling and PROSYM to perform production cost modeling.

b. Please explain why Plexos was not used to perform production cost modeling.

c. Please explain if the capacity expansion plans were optimized to meet a summer reserve margin, a winter reserve margin, or both a summer and winter reserve margin, and how the Company did so.

d. Please provide all PLEXOS modeling inputs and outputs, in spreadsheet format with all formulas and links intact, for all modeling runs performed for this IRP.

e. Please provide all PROSYM modeling inputs and outputs, in spreadsheet format, will all formulas and links intact, for all PROSYM production cost modeling modeling runs performed for this IRP.

A-1.4.

a. Confirmed.

b. The Companies have been using PROSYM for production cost modeling for decades and many tools supporting PROSYM have been developed to support its efficient use. Even though Plexos is capable of production cost modeling, it will take time to build the same level of analytical robustness and efficiency as PROSYM.

c. The capacity expansion plans were optimized to meet minimum reserve margin requirements for both summer and winter. Specifically, Plexos was used to identify the least-cost generation portfolio that meets minimum reserve margin constraints (i.e., 17 percent in the summer and 26 percent in the winter) at the end of the IRP planning period. Then, an annual resource plan was developed to meet minimum reserve margin constraints throughout the planning period.

d. See the response the Question No. 3.
   - PLEXOS inputs are located at the following file path: \0283_2021IRP\ResourceAssessment\PLEXOS\20211008_2021IRP - 26WRM scenarios

   - PLEXOS outputs are located at the following file path: \0283_2021IRP\ResourceAssessment\PLEXOS\CONFIDENTIAL - ConnectSolutions

e. PROSYM was used in developing the Resource Assessment and the RTO Analysis.
   - Resource Assessment files are located at the following file path: \0283_2021IRP\ResourceAssessment\ReferenceCase
   - RTO Analysis files are located at the following file path: \2021RTOAnalysis

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.5

Responding Witness: Stuart A. Wilson

Q-1.5. Please refer to Table 9-1 on page 9-1 of the IRP.

a. Please provide the supporting workbooks, with all formulas and links intact, used to develop the annual revenue requirements for all modeling runs performed for this IRP.

b. Please explain how the revenue requirements were developed from some or all of the PLEXOS, PROSYM, and other modeling conducted for this IRP.

c. Please provide the name of the model used to develop the revenue requirements.

A-1.5.

a. See the response to Question No. 3. These files are located at the following file path: \0283_2021IRP\ResourceAssessment.

b. Production costs were developed in PROSYM. All other revenue requirements were developed in a Microsoft Excel model.

c. The Companies' revenue requirement model was developed internally and does not have a name.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.6

Responding Witness: Stuart A. Wilson

Q-1.6. Please refer to pdf page 26 of Volume III. Why, in the Companies' opinion, are the results of one year (2025) of production cost modeling sufficient basis to conclude that "In other words, it is not cost-effective to alter annual or summer peak hour reliability by either retiring existing resources or adding new resources"?

A-1.6. See Table 14 and Table 15 on page 25 of the Reserve Margin Analysis. Considering the generation portfolios with a summer and winter loss-of-load expectation ("LOLE") less than one (i.e., total LOLE is less than four), when reliability and generation production costs are evaluated based on the 85th or 90th percentile of the distribution, the Companies' existing portfolio has the lowest total cost.

The key uncertainties in evaluating generation portfolio reliability are load and unit availability. Because these uncertainties do not change materially from one year to the next, it is appropriate to assess generation portfolio reliability over a single year. See the response to AG 1-30.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.7

Responding Witness: Stuart A. Wilson

Q-1.7. Please provide any workbooks used to post-process, adjust, or compile modeling results from any modeling performed in PROSYM, PLEXOS, or SERVM that was used in this IRP.

A-1.7. See the response to Question No. 3. See files at the following file paths:

- PROSYM
    - \0283_2021IRP\ResourceAssessment\ReferenceCase
    - \2021RTOAnalysis\PROSYM

- PLEXOS
    - \0283_2021IRP\ResourceAssessment\PLEXOS

- SERVM
    - \0283_2021IRP\ReserveMargin\SERVM

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.8

Responding Witness: Stuart A. Wilson

Q-1.8. Please explain if short term market purchases were available in the capacity expansion modeling. If purchases were allowed, please provide the annual amount and cost that was available for selection.

A-1.8. Short-term purchases were not evaluated as a resource in the Companies' Long-Term Resource Planning Analysis.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.9

Responding Witness: Stuart A. Wilson

Q-1.9. Please confirm if the Companies performed any modeling runs in Plexos or PROSYM that looked at market interactions with MISO or PJM. If modeling runs were performed with market interactions, please provide the input and output files associated with those modeling runs.

A-1.9. The Companies did not perform any modeling runs in Plexos or PROSYM that looked at market interactions with MISO or PJM.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.10

Responding Witness: Stuart A. Wilson

Q-1.10. Please refer to the discussion of why a CO2 price was not modeled on page 5-20 of the IRP. Please confirm whether any carbon reduction emissions were modeled as a constraint for the capacity expansion or production cost modeling.

A-1.10. No carbon emissions reductions were modeled as a constraint.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.11

Responding Witness: David S. Sinclair

Q-1.11. Please confirm that PPL has made public statements committing to the goals of achieving net-zero carbon emissions by 2050, a 70% reduction from 2010 levels by 2035, and an 80% reduction from 2010 levels by 2040. If confirmed, please explain in detail how, if at all, the 2021 IRP helps the Companies to achieve those goals.

A-1.11. PPL has set a goal to achieve net-zero carbon emissions by 2050, with interim reduction targets of 80% from 2010 levels by 2040 and 70% by 2035. The Companies' 2021 IRP specifically focuses on the CO_2 emissions reductions realized by the Companies over the IRP's planning period. See Table 20 on page 22 of the "2021 IRP Long-Term Resource Planning Analysis" in the IRP Volume III. The CO_2 emissions reduction forecasted for the base IRP scenario reflects a PPL-wide reduction of 68% by 2035.

PPL published its "Energy Forward 2021 Climate Assessment Report" in November 2021. See attached. The report demonstrates a range of forecasted potential PPL-wide CO_2 reductions through 2050, which includes the forecast presented in the Companies' 2021 IRP.

ENERGY FORWARD

PPL's 2021 Climate Assessment Report

Table of Contents

A Message from Our CEO

At PPL, we are committed to delivering a net-zero carbon future while keeping energy reliable and affordable for our customers and communities. Achieving these priorities won't be easy. The challenges ahead are complex, and the solutions will require historic investment, innovation and collaboration.

But every challenge presents opportunity, and the clean energy transition is no exception.

The transition offers us an opportunity to rethink how energy is produced, stored, delivered and used. In the process, it offers opportunities for us to further reduce our environmental impact, invest in new infrastructure, empower customers with new options, and drive innovation that benefits society.

As we continue to position PPL for growth in this clean energy transition:

- We've set a clear goal to achieve net-zero carbon emissions by 2050, with interim reduction targets of 80% from 2010 levels by 2040 and 70% by 2035.
- We're pursuing a broad-based clean energy strategy focused on decarbonizing our operations, investing in clean energy research and development, and enabling third-party decarbonization through smart networks.
- We're working with industry and policymakers to support necessary funding for energy infrastructure and research.
- We're keeping shareowners informed of our progress through transparent disclosures, including our Sustainability Report, EEI-AGA Report, CDP Questionnaire and Climate Assessment Reports.

In our 2021 Climate Assessment Report, we highlight risks and opportunities associated with climate change. We evaluate potential future emissions under multiple scenarios, including a scenario consistent with limiting global warming to 1.5° Celsius. And we outline our strategy and goals to enable a responsible transition that balances our commitments to the environment, our customers, our employees and our communities.

I'm proud of the progress PPL has made to date in executing this strategy – reducing our emissions nearly 60% since 2010. I'm pleased with the momentum we continue to build in 2021. This has included investing an additional $50 million to drive innovation in the clean energy space, launching a new partnership to study carbon capture at natural gas combined-cycle power plants, reaching new agreements to provide 125 megawatts of solar power to major Kentucky customers, and joining the Electric Highway Coalition to support greater adoption of electric vehicles.

I'm also very excited about the opportunities that lie ahead as we continue to develop one of the most advanced, clean-energy-enabling grids in the U.S. at our Pennsylvania operations; as we seek to replicate this success across our expanding regulated portfolio; and as we continue to transition our Kentucky coal-fired generation with an expected 2,000 megawatts of coal plant retirements over the next 15 years and replace it with non-emitting generation.

As we move forward with these initiatives and advance the clean energy transition, it's important that the industry and our stakeholders stay closely connected and clear-eyed on the challenges we must overcome to achieve net-zero while maintaining energy reliability and affordability. We look forward to the continued dialogue this report will foster in that regard. And I am optimistic that working together, we can and will achieve a net-zero future.

Sincerely,

Vince Sorgi

Vince Sorgi

Executive Summary

PPL's 2021 Climate Assessment Report, a comprehensive update of our 2017 report, takes into consideration international views on climate, new U.S. policies under consideration and recent changes to PPL's business mix.

This report is based on the four pillars of the Task Force on Climate-Related Financial Disclosures (TCFD) model framework and incorporates many of the recommendations set forth through implementation guidance. We continually work to incorporate TCFD's evolving implementation guidance through our sustainability efforts in order to inform our approach to supporting a clean energy transition and to communicate with our stakeholders in a transparent and consistent manner.[1] Our objectives for this report are the following:

- Describe governance and management methods to support a clean energy transition strategy.
- Articulate PPL's awareness of climate change impacts and understanding of related risks and opportunities.
- Show progress to reduce the company's climate change emissions and demonstrate scenario analysis to benchmark against 1.5°Celsius emission pathways and Paris Agreement-aligned commitments.
- Support the company's responsiveness and transparent reporting to shareowners and other stakeholders.

Our Approach to Climate Change

PPL's corporate governance and management practices are designed to help ensure long-term value for our shareowners, customers and the communities in which we operate. We have adopted a goal to reduce our carbon emissions to net-zero by 2050 and linked executive incentive compensation to several goals aimed at climate-related and ESG performance.

PPL is developing a strategic framework with the goal of positioning the company to help advance a clean energy future within our service territories and across the broader U.S. Our transition strategy is fundamentally centered around four key areas that we believe will enable us to advance new opportunities for the company and help deliver a net-zero economy by 2050:

- Decarbonize our electricity generation.
- Decarbonize our non-generation operations.
- Advance research and development.
- Enable third-party decarbonization.

We view our path to net-zero emissions on a continuum, with a primary focus on eliminating our gross emissions, leveraging technology to remove emissions where they cannot be eliminated due to cost or reliability constraints, and finally, considering carbon offsets for any remaining emissions as the least-preferred option.

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[1] *In addition to this report, PPL publishes several voluntary corporate sustainability disclosures. Our mapping of additional data and metrics to the TCFD framework and its pre-October 2021 implementation guidance, as well as additional details regarding PPL's work to advance a cleaner energy future, can be found at www.pplsustainability.com.*

We recognize that the urgency to change our nation's energy mix to address climate impacts will need to be balanced by the need for affordable and reliable power. The diverse perspectives of our varied stakeholders help to inform our approach to the risks and opportunities climate change presents.

Our holistic approach to planning, continued investments in our energy grid, use of data analytics and technology to drive reliability, and research into clean energy technologies are enabling us to deliver results today while working toward a long-term and sustainable clean energy transition.

Our Analysis

Emissions from generation resources we own represent the largest component of PPL's carbon emissions footprint and corporate-wide carbon reduction goal. Our climate assessment therefore focuses on three distinct future generation-related transition scenarios and a discussion of potential impacts:

- A Current Policies Scenario establishing PPL's future carbon emissions trajectory and potential range of reductions assuming no new regulatory requirements.
- A 1.5°C Scenario using an Intergovernmental Panel on Climate Change (IPCC) global climate mitigation pathway.
- A Fast Transition Future Policy Scenario considering the assumed power sector contributions under the U.S. Nationally Determined Contributions (NDC) to the Paris Agreement.

Key Takeaways

PPL's Current Policies Scenario analysis considers varying assumptions regarding changes in customer demand, as well as the relative economics of available technologies moving forward, the latter being driven primarily by the pace of technology development and commodity prices. PPL considered different variables in these areas given the inherent uncertainty in predicting future conditions.

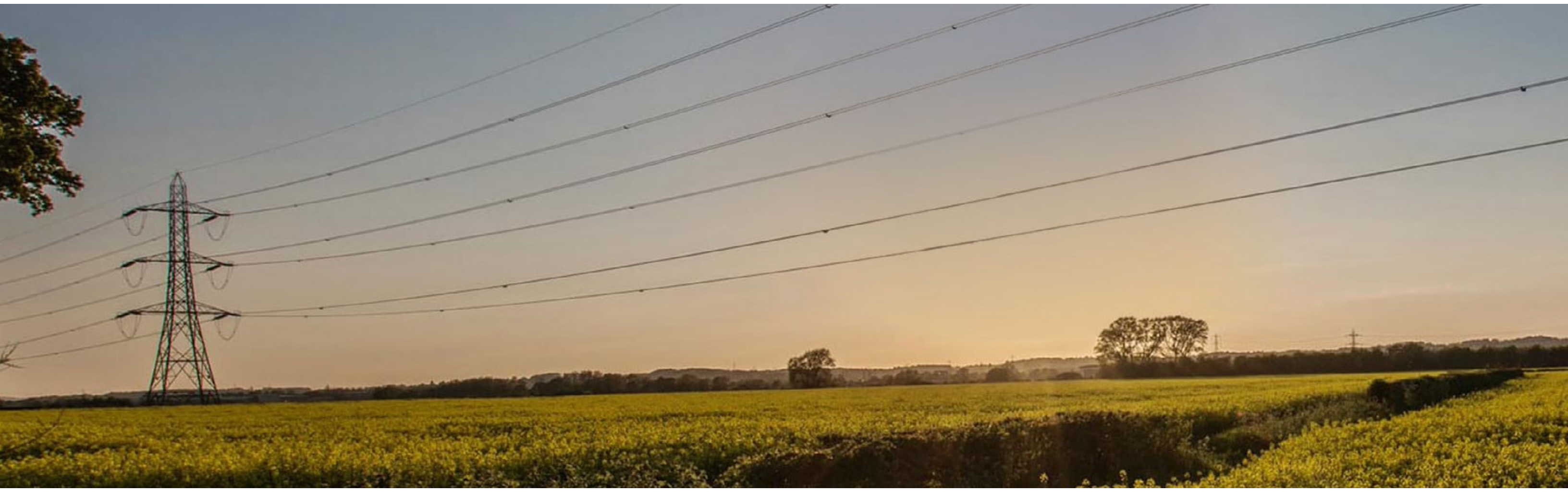
Scenario analysis results show that PPL's projected emissions from generation result in as much as an 85% reduction from 2010 levels by 2040 and net-zero emissions by 2050 at the low end of the emissions range. Reaching net-zero emissions in 2050 assumes that renewables and other non-emitting resources supported by clean energy technologies are widely and economically available.

However, policies that accelerate the pace and depth of reductions assumed in our fast transition future policy scenario would require significant changes to our energy portfolio. We believe that this pace of change would require an unprecedented level of technology advancement and investment in clean energy, not just at PPL, but across the economy.

Moving Forward

We will continue to make major investments across our transmission and distribution operations to mitigate weather-related climate risks and make the grid more reliable and resilient. Further, we will seek to align future capital investments with our clean energy transition strategy, including progress toward our net-zero carbon emissions goal. We are also leveraging smart grid technologies to actively manage our system and integrate distributed energy resources. And we are growing our clean energy portfolio while responsibly and economically retiring aging generation. Our partnerships and direct investments in clean energy research and development underscore our commitment to supporting economywide decarbonization.

PPL will continue to assess risks and opportunities associated with climate change. The analysis presented in this climate report is performed at a point in time with a certain set of assumptions. In practice, we are regularly engaged in short- and long-term planning across our business. In addition, we will continue to engage on related public policy matters and with our stakeholders to ensure we can respond effectively to future changes in policy and regulation as we strive to deliver value to our shareowners, customers and the communities we serve.



Introduction to PPL

ABOUT OUR COMPANY

PPL Corporation and our family of companies provide essential energy services to more than 2.5 million customers. We provide an outstanding service experience for our customers, and our companies consistently rank among the best utilities in the U.S.

As the energy grid evolves, so do we. We are modernizing the energy grid to enable more distributed energy resources (DERs), including renewable generation, on our networks. We are developing solar for customers across the U.S., and we are also taking steps to advance a cleaner energy mix.

We seek to be a positive force in the cities and towns where we do business, and the spirit of volunteerism and philanthropy runs deep at PPL. Our more than 5,600 employees generously volunteer their time and energy to help others. We also partner with hundreds of nonprofit organizations and provide financial support to help develop a strong, skilled workforce, revitalize our communities and enhance education.

Through the sale of PPL's U.K. distribution business in June 2021 and the planned acquisition of The Narragansett Electric Company, we are positioning ourselves for long-term growth and success by simplifying our business mix, strengthening our credit metrics, improving our prospects for long-term earnings growth, and creating greater financial flexibility to invest in sustainable energy solutions.

As PPL strategically repositions itself as a leading, high-performing, U.S.-focused energy company, we believe there will be additional opportunities to deploy capital into our utilities and renewables business in a disciplined manner that helps create long-term value for shareowners and supports the clean energy transition.

Our Structure

Headquartered in Allentown, Pennsylvania, PPL Corporation is the parent company to three regulated utility companies. Covering more than 19,000 square miles with more than 83,000 miles of electric and gas lines. PPL's regulated utilities provide electricity and natural gas to power our customers' lives.

Through our regulated utilities, we deliver electricity to approximately 1.4 million customers in eastern and central Pennsylvania and 1 million customers in Kentucky and Virginia. We also deliver natural gas to approximately 330,000 customers and operate more than 7,500 megawatts of generation in Kentucky. In addition, PPL is the parent company to Safari Energy, LLC, a leading provider of solar power solutions for commercial customers in the U.S. with more than 500 commercial-scale solar projects completed.

PPL previously owned Western Power Distribution (WPD), which is the U.K. electricity distribution network operator serving nearly 8 million end-use customers the East and West Midlands, South West England and South Wales. Under PPL's past ownership, WPD delivered operational excellence, superior customer satisfaction and innovative solutions to advance a cleaner energy future.

PPL in March 2021 announced its planned agreement to acquire Rhode Island's primary electric and gas utility, The Narragansett Electric Company, from National Grid for approximately $3.8 billion. The acquisition remains on track to close as expected by March 2022.

Our Strategy

PPL's strategy is focused on creating value for all stakeholders and centers on five strategic objectives to enable long-term growth and success:

- Achieve industry-leading performance in safety, reliability, customer satisfaction and operational efficiency.
- Advance a clean energy transition while maintaining affordability and reliability.
- Maintain a strong financial foundation and create long-term value for our shareowners.
- Foster a diverse and exceptional workplace.
- Build strong communities in the areas we serve.

How We Do Business

We Excel in Customer Satisfaction

Delivering electricity and natural gas safely and reliably is our No. 1 priority. PPL's businesses are recognized as among the very best in customer satisfaction. PPL Electric Utilities Corporation (PPL Electric), Louisville Gas and Electric Company (LG&E), and Kentucky Utilities Company (KU) have repeatedly been recognized among the top of their class for customer satisfaction with more than 50 J.D. Power Awards combined. Two of PPL's utilities were recognized by Escalent as Most Trusted Utility Brands in 2021.

We Are Building a Smarter, More Secure Energy Grid

PPL is driven by a determination to ensure that each of our customers has the power they count on every day. Fulfilling that commitment takes dedication, hard work and resources. PPL invested more than $30 billion over the past decade *(including U.K. operations)* to strengthen energy grid resilience in the face of future storms, reduce power plant emissions and prepare our networks to better integrate more DERs. Looking forward, we expect to continue to make investments that help deliver energy safely, reliably and affordably, as well as provide increasingly cleaner energy.

We Are Powering the Future

The energy grid is undergoing rapid transformation, and PPL's businesses strive to address new challenges head-on. The clean energy transition requires advancements in our generation, transmission and distribution businesses. On the generation side, it entails economically retiring our coal fleet and replacing that generation with cleaner alternatives, including renewables, non-CO_2 emitting technologies and battery storage. On the transmission side, it entails building out new transmission lines to connect large-scale renewable energy projects to the load zones where that energy is needed. And, on the distribution side, we are leveraging technology to enable a more flexible, two-way flow of electricity. This improves reliability and enables the distribution grid to host more DERs like solar and energy storage without the need for expensive grid upgrades.

PROGRESS SINCE OUR LAST REPORT

In 2017, PPL conducted a detailed assessment of how future requirements and technological advances aimed at limiting global warming could impact PPL.

The assessment examined several policy and technology scenarios, including a scenario consistent with limiting global temperatures to an increase of 2° Celsius over pre-industrial levels as set forth in the International Energy Agency's 450 Scenario. A report of this assessment is publicly available on PPL's website.

The 2017 scenario analysis showed that CO_2 emissions in Kentucky would be expected to decline dramatically by 2050 as aging generation units are retired and replaced with a mix of renewable and natural gas generation. The analysis showed more limited CO_2 reductions by 2030. In the absence of new policies, the general trajectory and range of emissions reductions expected from our generation fleet have largely been consistent with the ranges outlined under different retirement cases in our 2017 climate assessment.

PPL has taken a number of steps to advance our emissions reductions and overall clean energy transition strategy, which are discussed throughout this report. Highlights include adoption of a net-zero emissions goal, planned retirements of aging fossil plants, aligning executive compensation with ESG and climate-related metrics and reimagining energy delivery through investments in innovation and research and development.

PATH TO OUR 2050 NET-ZERO CARBON EMISSIONS GOAL

Analysis performed during the 2017 assessment formed the basis for PPL's first carbon reduction goal – an enterprise-wide goal to cut carbon (CO_2e) emissions 70% by 2050 from a 2010 baseline – and put the company on a deliberate path to help deliver a clean energy future for our customers.

In 2020, PPL adopted a more aggressive carbon reduction goal of at least 80% by 2050 and accelerated its previous 70% goal by 10 years to 2040 (see Metrics and Targets). Actions to date have reduced scope 1 and 2 carbon emissions covered by our goal by nearly 60% from 2010 to 2020.

During 2021, the company undertook two key initiatives in addition to this climate assessment to inform our generation planning and corporate clean energy transition strategy. LG&E and KU developed an updated integrated resource plan in Kentucky, and the corporation is undertaking an in-depth analysis of our clean energy transition strategy with the help of a leading global energy consultant. As a result of our ongoing, focused analysis, PPL modified its carbon reduction goal to net-zero by 2050, with 80% reduction by 2040 and 70% reduction by 2035.

To help achieve these reductions and support our net-zero-by-2050 goal, PPL has a four-part clean energy strategy aimed at decarbonizing our owned generation and operations, bringing smart grid technology and renewable energy solutions to our customers, and investing in research and development necessary to support the deployment of affordable and reliable clean energy technologies (see Strategy).

SIGNIFICANT ACQUISITIONS, DIVESTITURES AND BUSINESS DEVELOPMENTS

In 2018, PPL acquired Safari Energy, LLC, along with its solar generation projects spanning 24 states and Washington, D.C. Since the acquisition, PPL has expanded Safari's business model – previously limited to building and selling solar projects to large commercial customers – to include developing, acquiring and owning solar projects.

In 2019, LG&E and KU retired two units at the E.W. Brown plant, increasing the total retired coal-fired generation to 1,200 megawatts since 2010.[2] The companies expect to retire an additional 1,000 megawatts of coal-fired power plants in Kentucky by 2028, earlier than had been anticipated in the 2017 analysis. In 2020, LG&E and KU executed a 100 MW purchase power agreement ("PPA") with a developer for a new solar facility expected to be operational in early 2023. In late 2021, LG&E and KU executed a PPA for an additional 125 MW of solar generation expected to be operational in 2025. These PPAs support our customers' interest in renewable generation and will enable us to meet our obligations to serve our Kentucky customers' energy needs in the most reliable, least-cost fashion.

PPL is in the process of seeking regulatory approval to acquire Rhode Island's primary electric and gas utility, The Narragansett Electric Company. Rhode Island has set ambitious decarbonization and renewable goals, including legislation that requires a net-zero carbon economy by 2050 and an executive order by the prior governor establishing a 100% renewable energy goal by 2030. These goals are complementary with PPL's clean energy strategy and will provide PPL with the opportunity to leverage its experience in deploying smart grid solutions to enhance DER and renewables deployment in Rhode Island.

Lastly, as previously noted, PPL completed the sale of its U.K. electric distribution business in June 2021.

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[2] *PPL made a strategic decision to exit competitive generation in 2015, including over four gigawatts of coal-fired generation. Emissions from this generation are included in PPL's 2010 goal baseline.*

PPL's Approach to Climate Change

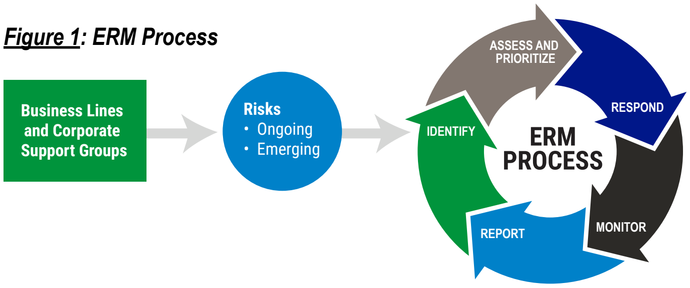
Providing sustainable energy to our customers is rooted in PPL's corporate mission, business strategy and sustainability commitments. We strive to economically and sustainably transition to cleaner energy sources through innovation, responsible resource management and investments in infrastructure that support a more reliable, resilient and efficient energy grid. Core to our strategy is understanding our business risks and opportunities and conducting disciplined planning for long-term success.

GOVERNANCE

Assessing and Managing Risk

Risk affects an organization's ability to achieve its strategy and business objectives. PPL employs enterprise risk management (ERM) as a comprehensive and integrated process for managing key risks to support the organization's achievement of its strategy and business objectives and maximize its enterprise value (Figure 1). Climate-related issues are incorporated into PPL's ERM and business strategy processes and communicated to PPL's Board and senior management.

Figure 1: ERM Process



Oversight and Integration into Strategy

Strong leadership and well-managed operations are the cornerstones of a successful business. PPL's corporate governance practices are designed to help ensure long-term value for our shareowners, customers and the communities in which we operate. The responsibilities of the Board of Directors include providing oversight of the management of PPL, selecting the company's leaders, approving long-range strategic plans and advising senior management.

PPL's Board of Directors reviews climate and environmental, social and governance (ESG) issues as part of corporate strategy discussions, including the company's clean energy transition strategy and the adoption of and progress toward carbon emissions-related goals. The full Board is informed by company leadership, outside experts and Board-level committees. Several Board-level committees oversee climate-related issues within their respective areas of focus and provide reports to the full Board (Figure 2).

Figure 2: Board Committee Oversight of Climate-Related Issues

Governance and Nominating Committee	Oversees the company's sustainability-related policies and practices; reviews key corporate sustainability disclosures and receives regular sustainability and ESG reports, including discussion of key climate and clean energy trends, risks and opportunities.
Audit Committee	Receives quarterly reports on enterprise risk management. The Audit Committee regularly reviews risk management activities, including issues related to the transition of the utility sector, such as sustainability and climate-related issues, as well as activities related to the company's financial statements and disclosures, and certain legal and compliance matters.
Finance Committee	Annually reviews and approves a multi-year business plan and capital expenditure plan. The Finance Committee also approves major capital financing, acquisitions and divestitures. Climate-related issues are addressed in the business and capital plans.
Compensation Committee	Reviews and approves annually the compensation structure, including ESG goals and objectives, for the company's executive officers.

The Corporate Leadership Council (CEO, COO, CFO, GC, CHRO, collectively "CLC") provides management and oversight of the company's overall risk management practices and business strategy, including the company's clean energy transition plans, targets and metrics. Guided by PPL's Investor Relations, CLC and other company leaders inform our investors of the company's business strategy, clean energy transition plans and progress toward climate goals.

Progress toward the company's 2050 net-zero emissions goal is included in executive compensation. The Board's Compensation Committee approved an incentive mix for CLC and other top executives that includes goals tied to priority ESG areas and climate-related performance, including goals linked to coal plant retirements, fleet electrification and building energy use.

PPL's Risk Management group reports to the executive vice president and chief financial officer and oversees the ERM process. Additional management committees, including a corporate sustainability committee chaired by the vice president – Public Affairs and Sustainability, ensure that PPL is effectively managing, monitoring and disclosing key ESG risk areas. CLC and company presidents review all corporate sustainability disclosures and receive updates and reports from ERM and sustainability management throughout the year and as important matters arise.

Engaging with Our Stakeholders

PPL engages with its stakeholders regularly and values the insights they provide as we work to deliver results for today and set strategic goals for the future. The diverse perspectives of our varied stakeholders help inform our approach to the risks and opportunities climate change presents.

We also understand the responsibility of balancing the reliability and affordability our customers expect with the increasing calls from investors, regulators and policymakers for carbon-free generation, grid innovation and technological advancements.

Policymakers and Advocacy

One pillar of our corporate strategy is advancing a clean energy transition while maintaining affordability and reliability, and PPL's advocacy efforts support this strategic objective. We voluntarily disclose our corporate political contributions and trade association activity on our corporate website, including positions related to climate policy.

With respect to climate change policy, PPL recognizes that to be effective, U.S. climate policy needs to be national and economy-wide in scope, with a focus on market-based solutions and incentives rather than simply the regulation of individual emissions sources. In addition, PPL believes that climate change policy should provide regional and state flexibility and equally value all forms of carbon reduction to achieve deep and lasting decarbonization in the most efficient way.

PPL recognizes that achieving our net-zero carbon emissions goal by 2050 will require new ideas, technology and systems to deliver power safely, reliably and affordably for our customers. Accordingly, PPL is investing in research and development of clean energy technologies. In addition, we are supporting the appropriation of significantly more resources to support the next generation of low-carbon electric resource technologies and low-carbon energy carriers such as hydrogen, ammonia, synthetic fuels and biofuels. Furthermore, federal renewable energy tax credits have been, and likely will continue to be, one of the most significant federal policies driving investments in clean electricity generation. PPL is working with federal policymakers to help ensure that all non-emitting generation and storage technologies qualify for federal tax credits, and that regulated utilities have the flexibility to use these credits in a manner that maximizes the economic viability of carbon-free generation and storage projects. Finally, the company also supports efforts to electrify other sectors of the economy and believes that federal energy and climate policy needs to encompass economywide efforts.

At the state level, PPL is engaging with policymakers and other stakeholders to support regulatory policies that foster greater innovation and support a more flexible, adaptable power grid necessary for economywide decarbonization. And, we are working with regulators to support cost-effective solutions to meet residential and business customer demand for renewables.

> *Progress toward the company's 2050 net-zero emissions goal is included in executive compensation. The Board's Compensation Committee approved an incentive mix for CLC and other top executives that includes goals tied to priority ESG areas and climate-related performance, including goals linked to coal plant retirements, fleet electrification and building energy use.*

Investors

Investors are increasingly seeking information on key ESG factors that can impact a company's long-term performance. PPL is committed to transparent disclosure of the risks and opportunities we face as we address climate change and transition to a cleaner energy future.

We believe that the most effective way to communicate with our investors is to supplement our quarterly earnings webcasts and dedicated investor relations website with direct engagement in meetings and phone calls throughout the year.

In addition, we provide a variety of voluntary disclosures to meet the direct needs of investors and strive to improve the quality of our reporting using ESG standards and frameworks. Our reporting in this area includes the following, all of which are readily available under PPL's sustainability section on our website:

- Reporting sector-specific ESG metrics using a reporting template developed through a joint-reporting initiative of the Edison Electric Institute and American Gas Association.
- Annually publishing a comprehensive corporate Sustainability Report and Global Reporting Initiative index.
- Aligning our climate-related disclosures with many of the recommendations of the TCFD, including participating in the CDP climate survey.[3]
- Mapping our corporate ESG disclosures to the Value Reporting Foundation's SASB Standards.

Responsible Clean Energy Transition

How we achieve a clean energy transition matters, and PPL recognizes that a just transition considers impacts on our employees, communities and customers.

Ensuring the long-term resiliency and sustainability of the communities we serve is a key factor not only in how we conduct our day-to-day operations, but also in our strategy to move forward to a clean energy future. As we work to integrate DERs; site, build and maintain more resilient and reliable infrastructure such as transmission lines and natural gas pipelines; and retire aging power plants, we are helping to ensure a balanced, responsible and clean energy transition.

We consider environmental and economic factors that impact employees, communities and customers when assessing and planning development activity. These factors are consistent with our mission and values of being environmentally conscious, investing in our community, and providing affordable service. Environmentally, properties are assessed for endangered species, biodiversity, impact to water resources and cultural- and heritage-related concerns as part of our siting process. Economics often drive projects toward public, commercial and agricultural properties, rather than residential properties. Our operating companies have a history of community engagement and public meetings to support development activities.

With power plants providing hundreds of well-paying jobs and ongoing tax revenues for the communities in which they are located, we know that the retirement of a power plant can have a significant impact on employees and the community. To help ensure a just transition for our employees and the communities we serve, attention is given to retiring power plants in a way that aims to be the least disruptive to the local economy. We engage with regulators, customers, employees and the community early and often during a multi-year process.

Employees

PPL is committed to operating in ways that help promote, protect and support human rights in the communities in which we do business.

Beyond complying with federal, state and local laws and regulations applicable to human rights, PPL's *Standards of Integrity* and *Supplier Code of Conduct* provide a framework for operations that reflect these values and principles, not only for our own operating companies but for vendors and suppliers as well, including:

- Treating employees with respect and dignity, with the goal of providing a work environment that is free from harassment and unlawful discrimination. PPL's companies seek to provide work hours, wages and benefits in compliance with applicable laws.
- Striving to uphold human and workplace rights in all operations, and to treat workers fairly and without discrimination.
- Recognizing and respecting employees' freedom of association and collective bargaining. Where employees are represented by a properly certified labor union, PPL complies with collective bargaining obligations and agreements.
- Respecting the rights of people in communities in which we operate and striving to conduct business in ways that protect the environment and mitigate adverse impacts from our operations.
- Opposing child labor and forced labor, and complying with applicable laws prohibiting exploitation.
- Requiring suppliers to comply with all legal requirements and expecting adherence to high ethical standards in the areas of freely chosen employment; working hours; respect in the workplace; wages and benefits; and health and safety.

As the way we generate electricity undergoes changes, so do our workforce needs. Our employees are notified in advance of potential plant closures, and our plans are designed to minimize the impact to our employees.

To ease the transition for employees, we engage with labor unions and staff to mitigate job reductions through normal attrition, relocations and retraining for new roles both within and outside the company. We also provide mentoring and encourage job shadowing of individuals in other business units as professional development.

In 2015, for example, we retired the three coal-fired units at our Cane Run Generating Station and installed a natural gas, combined-cycle power plant. Only 32 full-time staff were required to operate the new plant. During the transition, LG&E and KU were able to reposition some staff to other roles in the organization and to manage the remainder through voluntary retirement and attrition. All staff were provided an opportunity to meet their employment needs.

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[3] *PPL's climate disclosures, as of the date of this Climate Assessment Report, disclose against the TCFD recommendations before the date of the October 2021 supplemental guidance.*

Communities

We believe that for our company to be successful, the communities we serve must be successful. With philanthropic programs in each operating region, our charitable investments aim to help meet the needs of our communities. Working with nonprofit and community partners, our philanthropic investments support many efforts helping to drive communities forward through programs focused on diversity, equity and inclusion; equitable education; economic and workforce development; health and safety and sustainable local community projects.

PPL is engaged in economic development efforts with a view to supporting the clean energy transition beyond the borders of our generation plants and other operations. For example, the recent announcement from a leading automobile manufacturer to build two electric-vehicle battery manufacturing facilities in Kentucky is expected to result in more than 5,000 new jobs in the commonwealth alone. This is a significant development for clean energy jobs supported by our ability to provide competitive, reliable and increasingly clean energy solutions. Governor Beshear and the Kentucky Office of Energy Policy's recently released resilient energy strategy underscores workforce development as a key component of sustainable economic development for Kentucky.[4] LG&E and KU participated in working groups associated with affordability and economic development in the lead-up to the strategy announcement and expect to be engaged in discussions on this and other important topics included in the energy strategy framework.

We recognize that our infrastructure projects have the potential to significantly impact local communities. We leverage more than a century of experience developing and maintaining the systems that keep electricity and natural gas flowing, and we have long-established practices to ensure we are focused on engagement, access, affordability and community support in every project we develop. These practices include:

- Using environmental screening to identify all communities impacted by projects under development.
- Seeking early and frequent stakeholder engagement, including public open houses and public feedback surveys.
- Communicating with plant advisory committees and plant neighbors.
- Providing timely and transparent information.
- Working with local community leaders.
- Expanding community support and development efforts.

Across our service territories, our teams work with various partners as we aim to minimize our operational impact on sensitive resource areas, protecting biodiversity and ecosystems. We implement comprehensive Avian Protection Plans to help prevent birds from contacting electrical equipment and power lines and have adopted processes to promote native vegetative growth. In addition, we offer grants to environmental conservation organizations for community revitalization; support research and development projects related to pollinator habitat protection; work to identify and protect species of concern in proposed work areas; and provide trees and pollinator-friendly plants to county and municipal parks, environmentally focused groups and schools through various distribution programs. Since their inception, PPL's community tree planting programs in Kentucky and Pennsylvania resulted in the sequestration of nearly 1,700 metric tons of CO_2 through 2020.

Customers

We provide a variety of programs designed to meet the needs of customers, whether they are large industrial customers monitoring their own emissions and considering renewable energy purchases, small businesses looking for ways to be more energy efficient or low-income residential customers hoping to reduce their energy bills. We also support our most vulnerable customers through direct financial assistance and flexible payment options.

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[4] https://eec.ky.gov/Energy/Documents/KYE3_Final_10.18.2021.pdf

We strive to exceed our customers' expectations. That includes keeping our energy affordable and giving our customers options to reduce their energy use. PPL's operating companies engage customers through a variety of rebate programs, energy efficiency workshops, video and social media profiles highlighting customers' energy savings, and in-school curricula that teach students the importance of energy, natural resources and environmental protection. Collectively, PPL's energy efficiency programs enabled customers to save over 2 million megawatt-hours of electricity from 2017 to 2020, the equivalent of avoiding nearly 1.1 million metric tons of CO_2e.

In addition to direct customer engagement programs, the companies conduct community outreach programs, such as tree planting programs, sponsorships of environmental programs with community partners and collaboration with industry and academic partners. We believe engagement across all customer classes and our sustainability disclosures and online tools ensure all customers have the information they need regarding energy efficiency, PPL's carbon goals and how we can help customers achieve their own sustainability goals.

ASSESSING AND ACTIVELY MANAGING RISK

As part of the ERM process, representatives from PPL's business lines and corporate support groups identify, assess, prioritize, monitor and report on both ongoing and emerging risks. In addition to assessing risks through our ERM processes, PPL's operating companies assess and manage risks through the ongoing business planning process. We have provided a detailed summary of our assessment of potential portfolio impacts from physical and transition risks (Tables 1 and 2, in the Appendix). These risks are discussed further in the context of our business and operational planning and transition strategy.

Comprehensive Planning to Manage Risks and Drive Opportunities

Comprehensive planning processes drive our operating companies' business plans and five-year capital plans. This planning is increasingly informed by advances in technology, such as smart grid technology, that enables us to gather and analyze a wealth of data from our transmission and distribution systems and transform this data into actionable insights that improve decision-making and help us prioritize investments.

Our operating companies' business planning activities cover electricity and natural gas transmission and distribution (T&D), as well as the generation of electricity. Planning horizons vary by system (T&D, generation) and range from 5-year to 15-year outlooks. Additional details follow.

T&D Planning

Across our enterprise, PPL's operating companies conduct transmission and distribution planning each year to maintain compliance with federal, state and industry standards; enable us to deliver energy safely and reliably; and position PPL to support the clean energy transition.

PPL's planning focuses on strengthening grid resilience to reduce damage and speed recovery from severe weather impacts that could result from climate change. It also incorporates smart grid technology to reliably and efficiently integrate increased DERs, including renewable generation and energy storage.

PPL Electric and LG&E and KU use a five-year asset planning model to prioritize transmission and distribution capital allocation, as well as operation and maintenance activities.

PPL Electric also projects a 10-year plan that is submitted to the PJM Interconnection, the regional transmission operator, for inclusion in PJM's annual Regional Transmission Expansion Plan (RTEP) process. RTEP identifies system additions and improvements needed to keep power flowing reliably throughout the PJM region.

LG&E and KU develop a 10-year Transmission Expansion Plan, coordinating closely with their independent operator, TranServ International Incorporated; their Stakeholder Planning Committee; and their reliability coordinator, the Tennessee Valley Authority, to ensure the companies' ability to meet existing and future requirements. In addition, they actively participate in the Southeast Regional Transmission Planning process.

T&D planning considers a wide variety of factors, including load forecasts, facility ratings, expected generation, data received from customers regarding their load growth, inputs from severe weather events, and insights gained from analyzing the increasing amount of data we can collect to monitor changing conditions on the energy grid and assess the adequacy of our systems and equipment. For example, using corrosion rates and other data we can reliably predict when equipment might fail and replace it proactively. We use LIDAR technology to map trees along transmission rights-of-way and predictive data science to map vegetation risk and better target our efforts to improve reliability without increasing costs.[5] In addition, we can monitor waveforms recorded by relays to proactively identify when electrical equipment is at a higher risk of failure.

Integrated Resource Planning in Kentucky

In Kentucky, LG&E and KU routinely evaluate the best ways to serve customers under a wide range of scenarios. These scenarios evaluate uncertainties regarding future load, how customers use electricity, customer preferences for clean energy, fuel prices, fuel availability, potential environmental costs and other factors.

The purpose of the Integrated Resource Planning (IRP) process is to assess future options for LG&E and KU to meet their regulatory obligations to provide reliable electric service at the lowest reasonable cost. Through this process, LG&E and KU model options to meet current and future demand reliably and affordably.

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[5] *The Association of Edison Illuminating Companies (AEIC) selected PPL Electric as a winner of one of its 2021 AEIC Achievement Awards — the organization's most prestigious annual honor — for revolutionary work in vegetation management.*

The Integrated Resource Planning process begins with 30-year forecasts of customers' energy needs. LG&E and KU use information from a variety of sources to develop reasonable long-term forecasts that reflect not only the quantity of electricity required, but also the hour-by-hour demand. The companies' load forecast models consider such factors as weather conditions, daily usage patterns, future economic activity, population, and potential adoption rates of demand-side management programs, electric vehicles, private solar generation, energy efficiency measures and more.

Seasonal and daily variability of customers' energy needs drive the development of a generation portfolio that can reliably meet customers' needs in every hour of the year and under a broad range of weather conditions. For example, over the course of the year, approximately 50% of customers' energy needs occur at night when solar power is not generating electricity, with up to 65% occurring at night during the winter months.

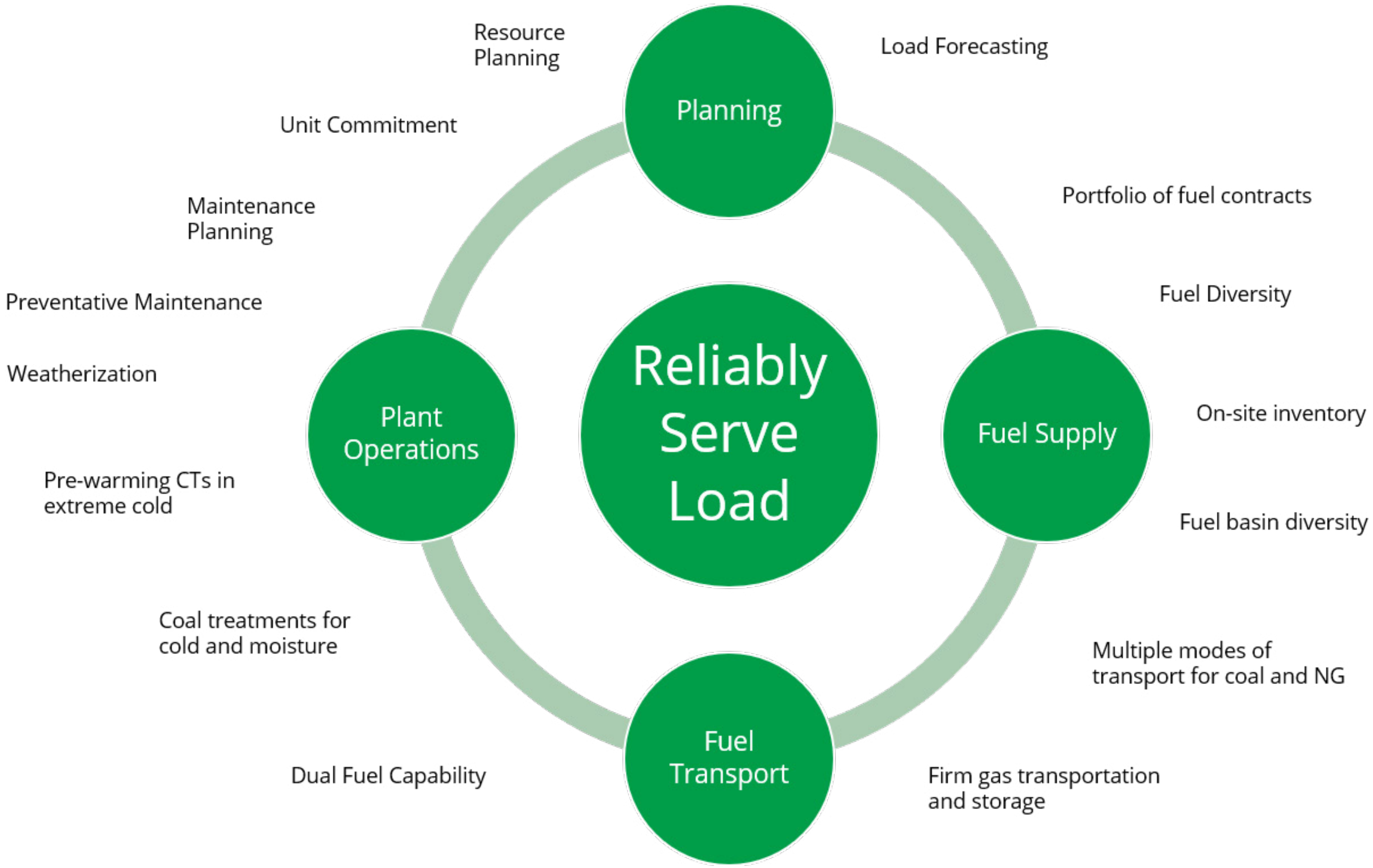
Currently, fossil-fueled generation is the lowest reasonable cost technology for meeting nighttime energy demand. However, as energy storage technology and economics improve, the combination of storage and renewable generation may serve peak demand, manage hour-by-hour changes in customer demand and supplant fossil fuel.

Considering all the above factors, LG&E and KU submit an Integrated Resource Plan to the Kentucky Public Service Commission (KPSC) once every three years, as required. However, the companies annually review and update their plan to reflect the latest information and forecasts and must affirm the adequacy of their resources annually in filings with the KPSC.

As a result of LG&E and KU's attention to planning and maintenance, the companies have demonstrated sustained excellence in generation reliability in recent years, reflecting top-quartile performance in its equivalent forced outage rates that are well below industry averages as tracked by ReliabilityFirst Corporation.

Seasonal and daily variability of customers' energy needs drive the development of a generation portfolio that can reliably meet customers' needs in every hour of the year and under a broad range of weather conditions. Figure 3 illustrates the holistic approach that LG&E and KU take to ensure reliability, which involves both short-term and long-term plans and actions.

Figure 3: Ensuring Reliable Generation Operations



Building a Stronger, More Resilient Energy Grid

As we strive to address climate change with the goal of advancing a cleaner energy future, PPL remains focused on strengthening the energy grid and making it more resilient to future storms and severe weather that may become more frequent with climate change.

Across our existing U.S. operating companies, we have invested more than $20 billion over the past decade on infrastructure improvements, much of that focused on incorporating new technology and hardening our T&D systems. Across our utilities, these improvements have reduced the number of outages our customers experience by an average of 35% over the past decade despite recent increases in storm activity and severity, including hazardous wind levels across our operating companies increasing by 30% to 50%.

Our efforts to strengthen the power grid are focused on:

- Replacing aging equipment, often to higher design standards.
- Installing smart grid technology and automation to enable real-time monitoring of system conditions, detect faults and quickly restore power to as many customers as possible when outages occur. The installation of more than 9,200 smart grid devices has prevented more than 1.4 million outages since 2015.
- Building new power lines and substations to support increased demand, add redundancy and give us greater flexibility to reroute power.
- Rebuilding existing power lines with stronger poles and wires to better withstand extreme wind and tree impacts.
- Clearing trees and other vegetation that pose a threat to power lines.
- Installing devices to prevent lightning and animals from damaging equipment.
- Enhancing cyber and physical security to protect critical T&D assets.
- Assessing flood risks at critical facilities, such as substations and power plants, and relocating facilities or installing defenses, where necessary.

35%

Average reduction in outages even in the face of increasing storm activity and severity.

Similarly, our efforts to modernize and upgrade our natural gas operations are focused on:

- Replacing gas lines with more durable materials. LG&E, for example, completed its gas main replacement program in 2017, replacing more than 540 miles of cast iron, wrought iron and bare steel pipes with primarily longer-lasting plastic piping that is less vulnerable to degradation. The project also included adding more valves to aid in response should damage occur. Currently, the company continues to replace aging steel service lines to customers' homes.
- Upgrading city gate, regulator and compressor stations with new valves, piping and modern regulating, measurement and protective equipment.
- Following comprehensive safety protocols that include using advanced in-line inspection tools to assess the condition of pipelines and conducting walking patrol and aerial leak detection surveys to find and repair leaks.

Completing the gas main replacement program significantly improved safety and reliability by mitigating risks related to flooding and extreme cold. The upgrades help eliminate water intrusion that can cause service interruptions. Our overall improvements have, to date, led to a decrease of below-ground gas leaks on our system by more than 70% since 2010.

As we work to upgrade both our electric and natural gas T&D systems, we continuously evaluate the impacts of severe weather events and use the insights gained to make our systems even stronger and more resilient.

For example, LG&E and KU use lessons learned from Hurricane Ike in 2008 and a severe ice storm in 2009 to enhance their hazard tree mitigation and pole inspection and treatment programs. PPL Electric, LG&E and KU use insights gained during severe ice storms and cold-weather events to add back-up generators to major gas facilities and winterize gas processing equipment and compressor stations so that they can operate in sub-zero temperatures. And PPL Electric responded to flood events at various substations from 2010 to 2015 by evaluating all substations on their system and modifying or relocating those within flood-prone areas.

In addition, PPL examined our potential vulnerability to extreme weather conditions such as those experienced in Texas during Winter Strom Yuri in 2021, which disabled the energy grid. Given the aforementioned practices and improvements, our access to regional transmission and our management of generation resources in Kentucky, we believe such extreme, widespread impacts to our energy grid are highly unlikely.

Ensuring Business Continuity in Emergencies

While PPL maintains a focus on system hardening and grid resilience to mitigate damage from severe weather events and other risks, we also recognize the importance of preparing for potential crises.

With crisis preparation in mind, PPL maintains a Corporate Emergency Management Plan, as well as operating company and hazard-specific plans for responding to a wide range of potential scenarios.

These plans are focused on ensuring business continuity and protecting the public, employees, the environment and our facilities and align with the National Incident Management System used by government agencies across the U.S. in responding to local disasters and emergencies. We conduct periodic tabletop and other exercises to ensure our ability to respond effectively and keep critical operations functioning when crises arise. Regarding severe weather events, PPL's operating companies actively monitor forecast conditions and model the potential impacts of storms before they arrive to anticipate resource needs and prepare in advance for possible outages.

These plans and processes were tested in 2020 during the COVID-19 pandemic. PPL has maintained a pandemic plan for more than 10 years and used this as the foundation for its response to COVID-19.

The company began monitoring and discussing COVID-19 activities in late January and early February 2020, activating a Pandemic Response Team, local emergency and business continuity plans, and the corporate Executive Crisis Team strategy.

PPL's strategy focused on balancing the safety of our employees with the critical needs of our customers. Efforts included:

- Isolating essential workers.
- Enhancing availability of technology equipment and systems to support a remote work environment for support roles.
- Implementing new protocols such as smaller work groups and remote reporting to minimize contact and increase social distancing for essential workers.
- Utilizing several resources to support effective communications to our workforce, including websites dedicated to COVID-19 work-related information and mass notification systems for consistent messaging.

Mitigating Financial Risk Through Regulatory and Liability Protections

Regulatory mechanisms enable PPL Electric, LG&E and KU to request from their respective public utility commissions, the authority to treat expenses related to specific extraordinary storms as regulatory assets and defer such costs for regulatory accounting and reporting purposes.

Once such authority is granted, LG&E and KU can request recovery of those expenses in a base rate case and begin amortizing the costs when recovery starts. PPL Electric can recover qualifying expenses caused by major storm events, as defined in its retail tariff, over three years through a Storm Damage Expense Rider.

In addition, PPL Electric uses a Federal Energy Regulatory Commission (FERC) formula rate, which is filed annually, to provide timely recovery of capital and operation and maintenance expense associated with the company's transmission system. This includes costs related to storm events. LG&E and KU also use an annual FERC formula rate that applies to non-affiliated transmission customers.

And, for generation, LG&E and KU have a regulatory asset recovery rider for recovery of future coal plant retirements, as well as an environmental cost recovery rider.

PPL's operating companies also maintain insurance coverages to help mitigate the financial impact of severe weather events. For instance, we maintain coverage to protect from potential property damage losses due to the extreme weather impact on our physical assets such as generation units, substations and buildings. Covered perils include but are not limited to flood, earthquake, named windstorm and hail damages to operating company assets. The PPL Electric property insurance program does not cover storm damages to utility poles and wires. These are covered through public utility commission rate cases and the Storm Damage Expense Rider outlined above.

STRATEGY

Assessing Our Portfolio

In 2017, PPL conducted a detailed assessment of how future requirements and technological advances aimed at limiting global warming to 2°C above pre-industrial levels could impact PPL. Since that time, the Intergovernmental Panel on Climate Change (IPCC), the United Nations body for assessing the science related to climate change, has issued two reports of particular relevance to our analysis, one in 2018 and another in 2021. These reports show that impacts from global warming are already being observed and that, in the aggregate, climate-related risks are larger if global warming exceeds 1.5°C above pre-industrial levels before returning to 1.5°C above pre-industrial levels. The risks depend on several factors, including the magnitude and rate of warming, peak and duration of warming, geographic location and adaptation actions. Significantly greater and more expansive global adaptation actions are required in scenarios that include a significant temperature overshoot.

Generation Scenario Analysis

PPL acknowledges the IPCC's view of climate trends and associated physical impacts of climate change. As our emissions from generation resources that we own represent the largest component of PPL's carbon emissions footprint and corporate-wide CO_2e reduction goal, we focused our climate assessment on three distinct future generation-related transition scenarios that consider PPL's owned generation emissions and future resource mix:

- A Current Policies Scenario establishing PPL's future carbon emissions trajectory and potential range of reductions assuming no new regulatory requirements.
- A 1.5°C Scenario benchmarking the range of reductions against an IPCC global climate mitigation pathway.
- A Fast Transition Future Policy Scenario benchmarking the range of reductions and forecasted resource mix against the expected contribution pathway for the power sector under the U.S. Nationally Determined Contributions (NDC) to the Paris Agreement.

These scenarios are designed to describe possible future states and potential implications for PPL within those future states. While grounded in plausible assumptions, PPL's scenarios and forecasts are not specific predictors of the future and do not constitute future business plans. The results of our climate scenario analysis and assessment are shown in the section of this report titled, "Results and Implications for Our Business."

Current Policies Scenario

As we did in 2017, PPL modeled our Kentucky power generation resources under a "Current Policies Scenario" where changes in resource mix are shaped by key technology and economic drivers, rather than changes in policy or regulation. This approach sets forth a future range of emissions reductions from owned generation and establishes a baseline for comparison of alternate approaches.

In this scenario, future coal plant retirements take place when they reach the end of their economic lives. New generation is a mix of non-CO_2 emitting technologies, renewables, battery storage, and natural gas (to support grid reliability) based on the relative assumed economics of these and new technologies, future fuel prices, and reliability requirements to meet customers' energy needs throughout the year. Future emissions are a function of load projections and the emissions profile of the generation mix used to serve that load. The reference case contained in LG&E and KU's IRP filed with the Kentucky Public Service Commission in October 2021 is included in this scenario forecast.

1.5°C Scenario – Global emissions pathways

PPL consulted the IPCC's global analysis, because we believe the IPCC's work is among the most respected and robust analyses of the temperature impacts of various mitigation pathways. In using this analysis, we recognize the challenges associated with translating global emissions pathways to our sector and our operations in the United States, as further explained below.

The IPCC began publishing its global climate assessment reports in 1990 and is currently in the sixth assessment cycle of reporting.[6]

The 2021 IPCC climate change report builds on the IPCC's 2018 special report referenced in the footnote below. The 2021 report provides an update on the current state of the climate (including how it is changing and the role of human influence), the state of knowledge about possible climate futures, climate information relevant to regions and sectors, and limiting human-induced climate change. The report posits that climate risks can be reduced by the expansion and acceleration of far-reaching, multi-level and cross-sector climate mitigation, and by both incremental and transformational adaptation. This report reaffirms, with greater certainty, the conclusions of earlier IPCC reports.

The 2021 report's summary for policymakers includes the following observations of climate trends:

- The scale of recent changes across the climate system as a whole and the present state of many aspects of the climate system are unprecedented over many centuries to many thousands of years.
- Human-induced climate change is already affecting many weather and climate extremes in every region across the globe. Evidence of observed changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones, and their attribution to human influence, has strengthened since the Fifth Assessment Report completed in 2014.
- Future greenhouse gas emissions will cause future additional warming, with total warming dominated by CO_2 emissions.

For our "1.5°C Scenario" analysis, PPL selected the 2018 IPCC special report mitigation pathways as they are consistent with the 2010-2050 timeframe of PPL's enterprise-wide CO_2e goal (the IPCC pathways achieve global net-zero CO_2 emissions around 2050) and enable us to compare emissions reductions over this period. The energy-related and carbon removal assumptions are also clearly and concisely described for each pathway in the 2018 report.

The 2018 special report put forth four illustrative model pathways (P1, P2, P3 and P4) showing different mitigation strategies that could achieve the net emissions reductions required to limit global warming to 1.5°C with no or limited temperature overshoot. PPL chose the IPCC's P3 mitigation pathway to benchmark future emissions range and trajectory as it is characterized as a "middle-of-the-road" scenario in which societal and technological development follows historical patterns, and emissions reductions are primarily achieved by changing the way in which energy and products are produced.

The P3 pathway, like all IPCC mitigation pathways, assumes levels of carbon capture and sequestration that depend upon future advancements in carbon capture technology, as well as availability of biological and terrestrial sequestration on a large scale. Significant research in these areas is currently underway across the globe, including soil carbon sequestration, transformation of carbon emissions into algae biofuels and building materials, and carbon capture and storage in deep geological formations. However, we recognize that the assumed levels of carbon capture and sequestration may turn out to be unachievable within the assumed timeframes.

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[6] *In 2018 the IPCC issued a special report on global warming of 1.5°C titled "Global Warming of 1.5°C: an IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development and efforts to eradicate poverty (SR1.5)." On August 9, 2021, the IPCC published Working Group I's contribution to the sixth assessment titled "Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change." By the spring of 2022, the IPCC expects to complete the sixth assessment cycle report by publishing reports from Working Group II (impacts, adaptation and vulnerability) and Working Group III (mitigation).*

We also recognize that the P3 Pathway assumes continued emissions from the power sector well beyond the 2035 date for decarbonization of the power sector that is currently contemplated in proposed U.S. federal legislation. See the Fast Transition Future Policy Scenario below.

The IPCC's P3 Pathway

Our evaluation of the P3 pathway focused on the following key assumptions[7] that are relevant to our power generation and have implications for electric transmission and distribution, and gas distribution assets (all comparisons are from a 2010 baseline):

- CO_2 emissions are reduced by 41% by 2030 and 91% by 2050.
- Energy demand increases by 17% by 2030 and 21% by 2050.
- Renewable share of electricity increases to 48% by 2030 and 63% by 2050.
- Primary energy from coal is reduced by 75% in 2030 and 73% in 2050 (possibly suggesting some new build or expanded operation post-2030).
- Primary energy from gas goes up 33% by 2030 and comes down to 21% by 2050.

The global generation trends above are directionally consistent with the U.S. Energy Information Administration (EIA) reference case projections for the U.S. electricity sector[8] (Figure 4), particularly with respect to renewables. The EIA projects that renewables will become the predominant source of energy generation, surpassing natural gas in 2030, although as a smaller percentage of total generation than anticipated in the IPCC global assumptions. The EIA projects that the renewable share of generation will double from 21% in 2020 to 42% in 2050 while coal declines from 19% in 2020 to 11% in 2050. Generation from natural gas is projected to decrease slightly from 40% in 2020 to 36% in 2050.

However, one key difference between the IPCC 2018 mitigation pathways and the EIA projections is the assumed share of nuclear energy. The P3 pathway assumes that globally there will be more than a 500% increase in the share of nuclear generation by 2050, the greatest increase among the pathways, versus the EIA's view that nuclear energy will decline by 8% in the U.S. between 2020 and 2050. In this regard, we believe that the IPCC's global view cannot be directly applied in the U.S. where expansion of nuclear on this scale is highly unlikely; however, we have not assessed the extent to which these assumptions impact the trajectory of the P3 mitigation pathway.

We find the IPCC global pathways to be generally useful in evaluating possible business impacts in a range of future possibilities, particularly as policymakers, investors and other stakeholders are keenly focused on them. However, there are limitations to and uncertainty in this type of analysis.
In selecting the IPCC's 2018 mitigation pathways for analysis, we understand that adherence to these pathways will be challenging considering the substantial cross-sector and multi-national coordination necessary to achieve the rapid decarbonization of energy supply and significant advances in low-carbon technologies. We also recognize that these scenarios are based on global emissions from all sectors, limiting the level to which the scenarios can provide insights with respect to PPL's operations. In fact, research by the Electric Power Research Institute (EPRI) has shown that there are challenges in translating global emissions pathways to the actions of a nation, region or sector and even more to the actions of an individual utility company. In its April 2020 report[9], EPRI notes, "At the highest level, there is uncertainty in the relationship between a global temperature goal and global greenhouse gas emissions. From there, the uncertainty only increases as we move from global to country to local emissions with additional factors entering the story at each level."
For example, a company may increase its generation and emissions, but displace higher emitting generating units within a power market. As a result, assuming emissions reduction targets across all sectors or even for all electric utilities, for example, may not be appropriate in all cases.

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[7] *See IPCC Figure-2.16 and IPCC Figure SPM.3B.*

[8] *U.S. Energy Information Agency Annual Energy Outlook 2021.*

[9] *Review of 1.5˚C and Other Newer Global Emissions Scenarios Insights for Company and Financial Climate Low-Carbon Transition Risk Assessment and Greenhouse Gas Goal Setting.*

When selecting the IPCC P3 Pathway, PPL also considered the International Energy Administration (IEA) Net Zero by 2050 Scenario.[10] The report calls for a total "extremely ambitious" transformation of the energy systems that underpin the world's economies and sets forth a roadmap with more than 400 milestones showing how this transformation should happen, including an immediate end to new investment in fossil-fuel extraction and driving to net-zero electricity by 2040, with richer nations reaching net-zero emissions in 2035. The IEA also assumes the phase-out of CO_2 unabated coal power globally by 2030 and CO_2 unabated gas by 2040.

These global assumptions are more aggressive than those of the IPCC and the EIA reference case projections for the U.S., and we believe that the IPCC P3 pathway offers a measured view of global energy trends. However, we recognize that expected power sector contributions for richer nations under the IPCC mitigation pathways may be steeper than total global reductions. We consider such steeper power sector reductions in the policy scenario described below.

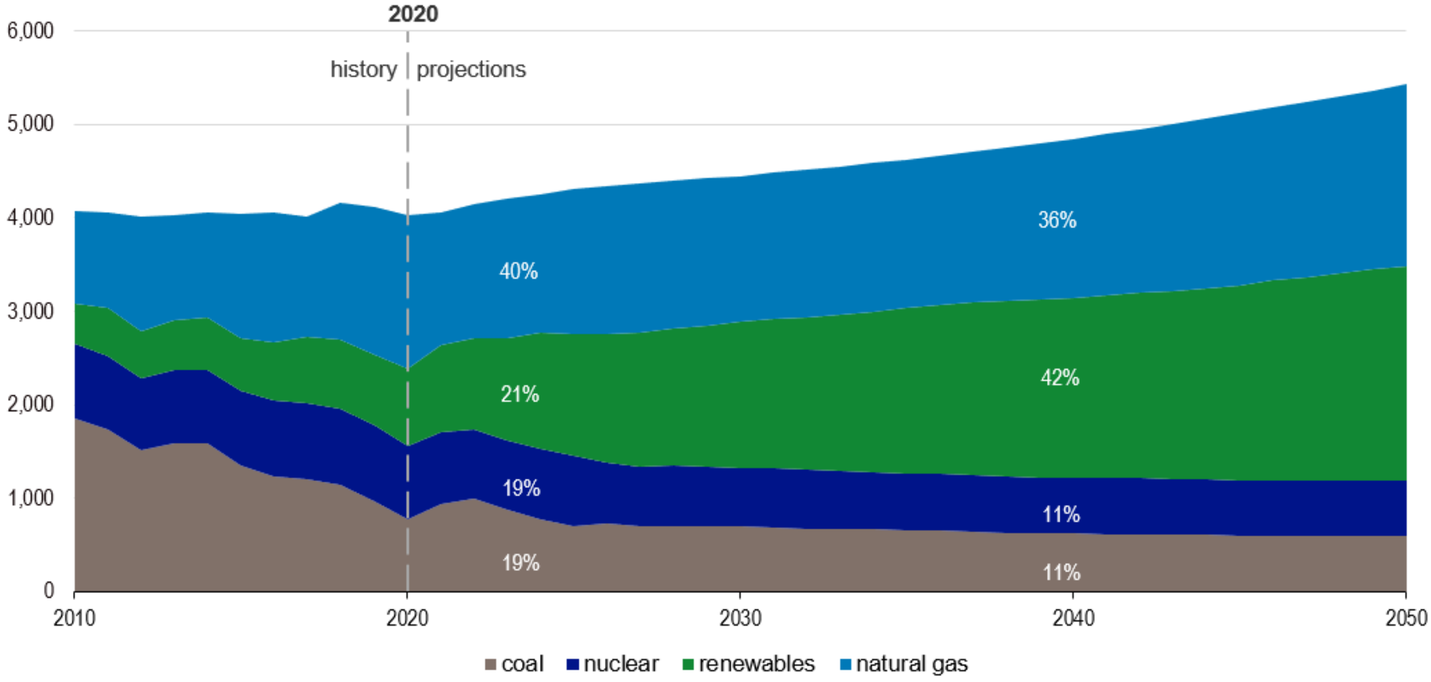
Fast Transition Future Policy Scenario

In looking at future policies that would drive a rapid transition to clean energy sources, PPL has focused on possible regulation at the federal level because our fossil generation assets (which are the ones at risk from climate change regulation) are all located in Kentucky, a state that is not currently contemplating CO_2 emission reduction requirements on power generation. The "Fast Transition Future Policy Scenario" considers the assumed power sector contributions under the U.S. Nationally Determined Contribution (NDC).

In the U.S. NDC submission under the Paris Agreement, the Biden Administration sets an economy-wide target to reduce net greenhouse gas emissions 50-52% below 2005 levels in 2030 with the expectation of achieving economy-wide, net-zero emissions no later than 2050. To achieve these levels of reduction, the Biden Administration envisions deep decarbonization in energy and other sectors and is promoting policies to achieve that objective.

At the time of this assessment, there were several clean energy policies being considered at the federal level. Given legislative and regulatory uncertainty, we did not pick a specific legislative proposal. We are assuming a future federal policy that requires 100% clean electricity by 2035, which is the expected contribution pathway from the power sector under the U.S. NDC, and an interim requirement of 80% clean electricity by 2030. The interim clean energy requirement is assumed to be the level that the power sector needs to reach in 2030 to support the economy-wide target of 50-52% reduction from 2005 levels and represents approximately an 85% reduction[11] in power sector emissions from a 2005 baseline.

***Figure 4*: U.S. Electricity Generation from Selected Fuels (2010-2050)**



Source: U.S. Energy Information Administration, Annual Energy Outlook 2021 (AEO2021)

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[10] *Net Zero by 2050: A Roadmap for the Global Energy Sector. International Energy Administration (IEA), May 2021.*

[11] *2030 U.S. NDC: Policy Progress in all Corners of the Economy. Starla Yeh, March 30, 2021,* *https://www.nrdc.org/experts/starla-yeh/2030-us-ndc-policy-progress-all-corners-economy-0*

PPL recognizes that future policies could also impose a compliance obligation on regulated transmission and distribution utilities in restructured markets. As we would expect that obligations generally could be met by these utilities purchasing additional clean energy subject to state regulatory approvals, we believe the focus of our scenario analysis is appropriately focused on our owned generation in Kentucky.

Key Assumptions for Current Policies Scenario

As noted earlier, PPL's scenario analysis sets forth a future range of emissions reductions from owned generation under a Current Policies Scenario. In modeling the Current Polices Scenario to 2050, PPL relies on the following base assumptions:

- Current Kentucky fossil generation facilities are retired at the end of their economic lives.
- Future resource decisions are based on the relative economics of technologies available at the time decisions are made, rather than future policies that favor specific technologies.
- There is no CO_2 price or additional cost associated with emission reductions as reductions are driven by technology advancements and relative economics.
- 725 MW of new solar is added by 2028 (225 MW by 2025 and an additional 500 MW by 2028).
- Retrofitting coal generation facilities with CCS remains uneconomic.

Load

PPL developed high and low load forecasts for Kentucky to support scenario modeling (Figure 5). The base load forecast is flat to declining as energy efficiency gains are assumed to offset increased consumption from new customers. In the high load forecast, new industrial customers are assumed to locate in PPL's service territories and favorable economic conditions result in higher customer growth (0.6% CAGR versus 0.4% CAGR in base case). In addition, the high load forecast reflects accelerated growth in electric space heating and electric vehicles (Figure 6).[12] As a result, the portion of energy consumed at night and in the winter months is significantly higher in the high case.

In the low load forecast, existing industrial customers are assumed to leave the service territory and unfavorable economic conditions result in lower customer growth (0.2% CAGR versus 0.4% CAGR in base case). In addition, the low case reflects an even faster pace of energy efficiency improvements than in the base case and significantly higher penetrations of distributed solar (Figure 7).[13] In both the high and low cases, LG&E and KU become winter peaking under normal weather conditions.

Economics and Technology

PPL's scenario analysis considers varying assumptions regarding the relative economics of available technologies moving forward, which are being driven primarily by the pace of technology development and commodity prices. PPL considered different variables in these areas given the inherent uncertainty in predicting future conditions.

***Figure 5**: Energy Requirements*

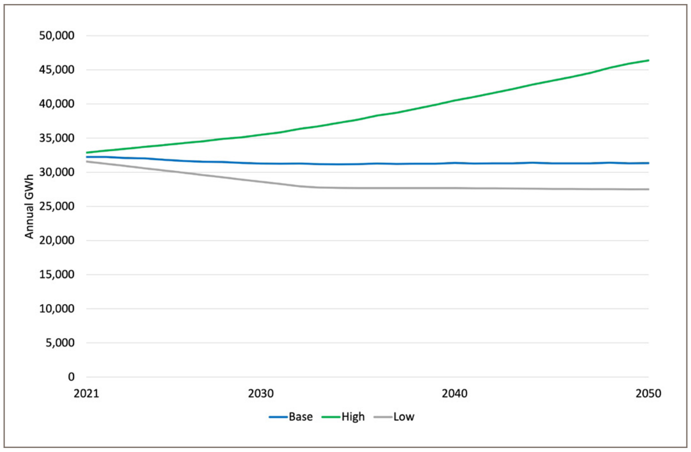


***Figure 6**: Number of Electric Vehicles*

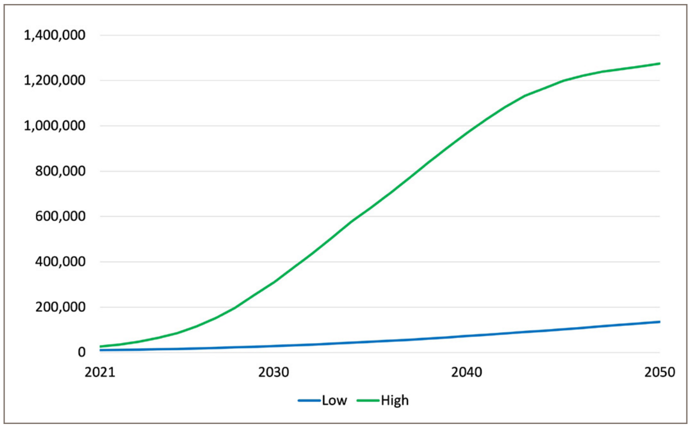
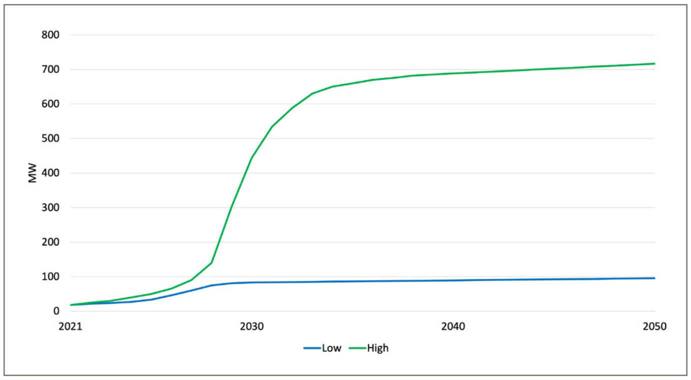


***Figure 7**: Distributed Solar Installed Capacity*



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[12] *By 2030, electric vehicles are assumed to account for 50% of new vehicle sales.*

[13] *End-use appliance efficiencies are assumed to reach 2050 forecasted levels by 2030. In addition, the existing cap on net metering is assumed to be removed.*

The high end of PPL's Current Policy Scenario emissions range reflects substantial growth in energy usage through 2050, slower development of zero-emissions technology, low natural gas prices, and solar and battery storage costs that decline less than forecasted under the moderate technology innovation scenario projections in the National Renewable Energy Laboratory's 2021 Annual Technology Baseline. In addition, the relative economics of available technologies are assumed to result in fewer zero-emitting resources through 2040. By 2050, relative economics favor zero-emissions resources.

The low end of the emissions range reflects declining energy usage through 2050, less energy consumed at night, faster development of zero-emissions technology, high natural gas prices, and solar and battery storage costs that decline faster than forecasted by the National Renewable Energy Laboratory. The relative economics of available technologies are assumed to favor zero-emitting resources by 2040, and at the outer boundary of this range, economics would result in the retirement of all fossil plants by 2050.

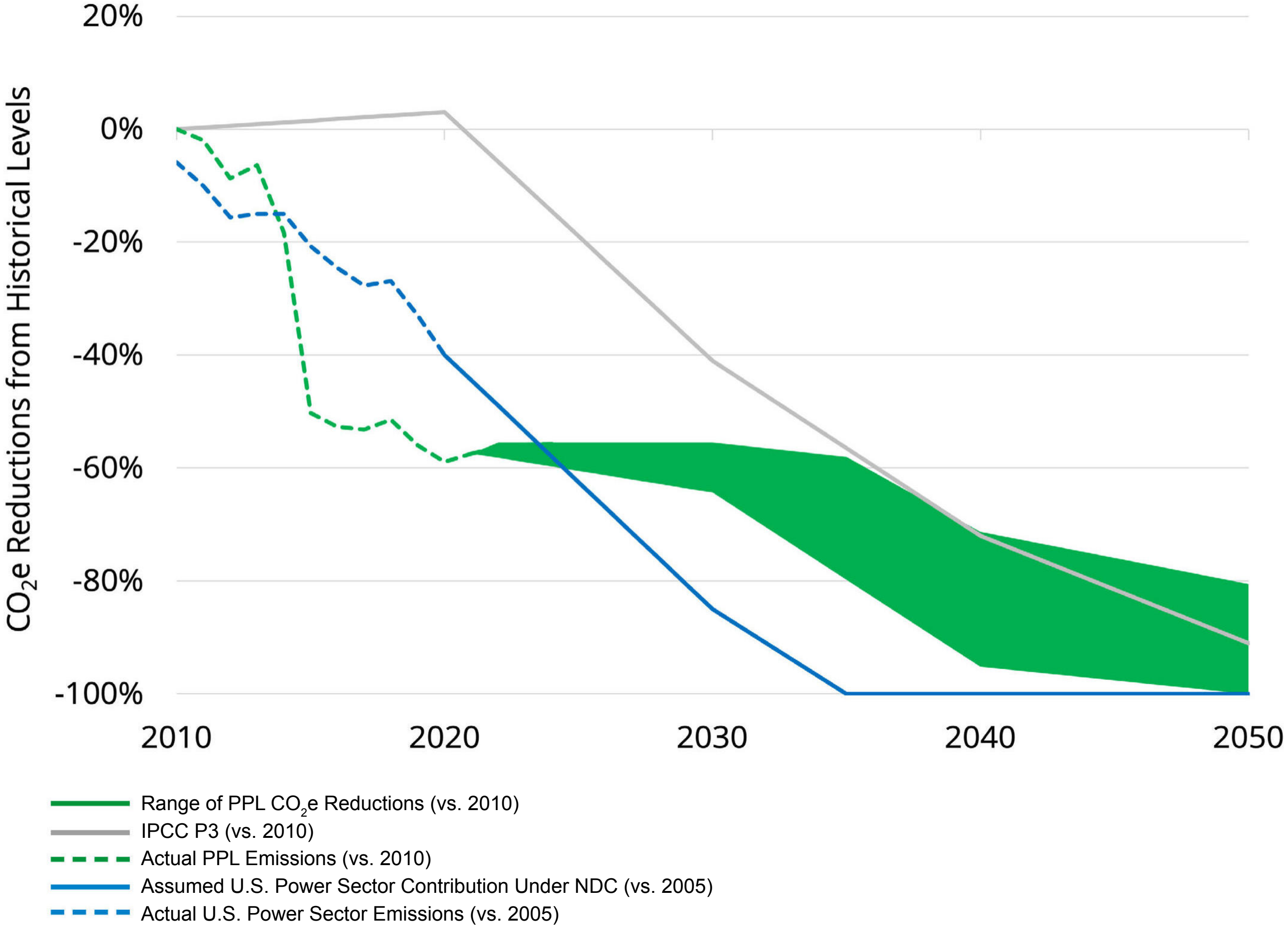
This range was used as a comparison to assumed reductions under a 1.5°C Scenario (IPCC P3 pathway) and Fast Transition Future Policy Scenario (Figure 8).

Results and Implications for Our Business

The significant increases in renewable and non-emitting energy resources assumed in the 1.5°C and the Fast Transition Future Policy scenarios would undoubtedly drive the continued transformation of the power grid beyond generation, and we expect this to present more opportunities than risks for us as we invest in enabling a more flexible grid that can support two-way flows of electricity, creating more efficiencies, and connecting more distributed energy resources like micro-grids, solar, electric vehicles and battery storage to the grid. On the generation front, we believe that there are significant opportunities for innovation and investment as the power sector will play a critical role in decarbonizing the overall economy.

PPL's historical and projected emissions (on an absolute reduction basis) are generally in line with the overall emissions reductions assumed in the IPCC P3 pathway.[14] At the low end of the range, non-emitting resources grow significantly in the 2030s, and PPL's emissions reach zero to net-zero emissions in 2050 depending upon resource mix (i.e., 100% renewables and storage vs. a mix of renewables and other non-emitting resources).

***Figure 8*: Comparison of Scenarios**



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[14] *Absolute emissions percentage reductions are from PPL's 2010 net-zero goal baseline. Absolute emissions reductions from a 2010 baseline of Kentucky-only emissions are projected to be consistent with the mid-to-low end of the Current Policies range of reductions and do not change our view of results or potential business implications.*

At the high end of PPL's projected emissions range, assuming high load, low gas prices, lagging clean energy technology developments and no intervening carbon policy, emissions would overshoot the 2050 net-zero emissions goal. This is a very conservative view, and we believe that there is a low probability of actual emissions results to be in this high range. Reaching net-zero emissions in 2050 assumes that renewables and other non-emitting resources supported by clean energy technologies are widely and economically available. Considering our 2021 IRP base case assumptions through the 2036 planning period and continuing reductions with a straight-line trajectory from that point, we would forecast emission reductions to fall within the mid to lower end of the range with emissions reaching nearly 90% below 2010 levels by 2050, supporting our view that clean energy technology will be necessary to achieve net-zero without the use of carbon offsets.

However, change on the scale and at the pace necessary to meet the U.S.'s economy wide NDC would entail modifying the company's generation resource mix shown in Figure 9 beyond what we assume economics and technology would deliver to support emission reduction levels shown in Figure 10. PPL's 2035 interim goal targets a 70% reduction from 2010 levels, and the low end of the projected range (assuming favorable economics and technology development) shows reductions reaching 80% in 2035. These projected reductions fall short of the 100% reduction expectation for the power sector under the U.S. NDC. In 2030, PPL's projected emissions at the low end of the range reach nearly 65% vs. an assumed 85% reduction. The scope of effort to reach the emissions levels contemplated under the U.S. NDC is discussed in more detail below.

When contemplating the various scenarios and in particular the Fast Transition Future Policy Scenario, it is important to understand that, given the significant uncertainty surrounding technological and regulatory developments, it is difficult to predict how we will be impacted and adapt to these developments. We would expect to work with state and federal regulators on any compliance plans stemming from any future regulatory requirements and believe that compliance costs would be subject to rate recovery.

***Figure 9*: Energy Mix**

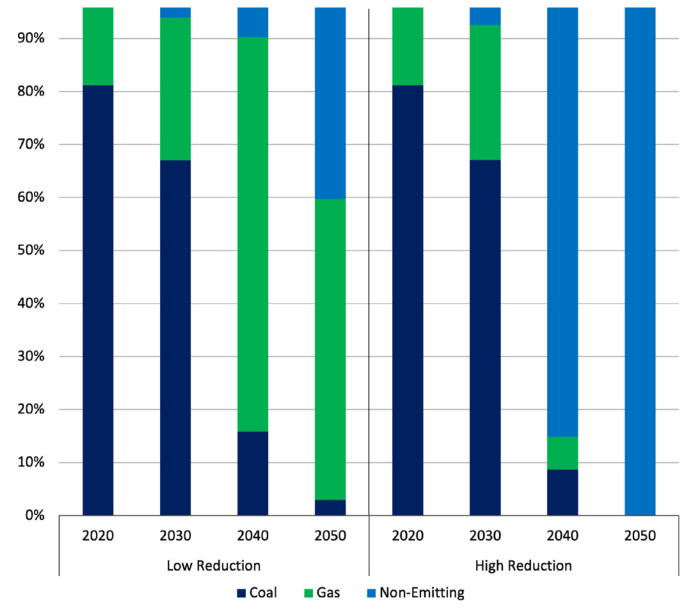
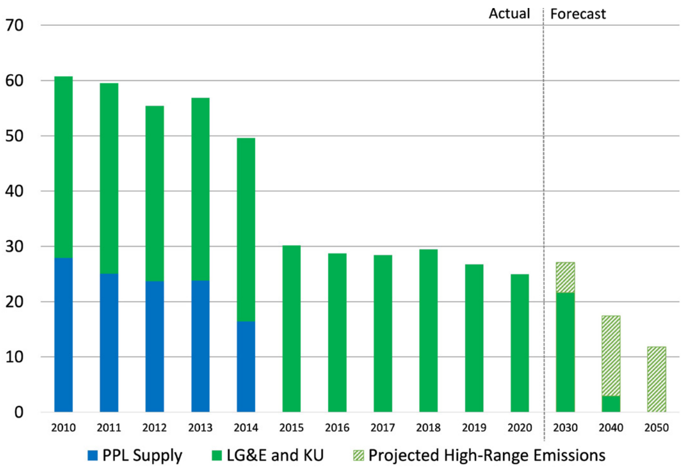


***Figure 10*: CO_2e Emissions (Metric Tons)**



Technology, Interdependencies and Pace of Change

To reach the emissions levels contemplated under the U.S. NDC and corresponding sectoral pathways, EPRI estimates that the U.S. would need to achieve annual energy-related emissions reductions that are three times higher than the level achieved from 2005 – 2020, going from 1 gigaton every 15 years to 1 gigaton every 5 years. The rate of each sectors' emissions reduction would need to accelerate to reach a "3X" increase in economywide reductions. The building, transportation and industry sectors would need to significantly accelerate their level of reductions, and the power sector would need to play a crucial role in helping them do so through electrification, energy efficiency and clean energy.[15] Accordingly, EPRI finds that achieving net-zero emissions by 2050 would require time and significant technology advancements.

The IEA report referenced above is also instructive in understanding the scope and breadth of action necessary to decarbonize the energy sector and the interdependencies of actions and technology necessary to achieve a net-zero emissions economy. The report identifies seven "key pillars of decarbonization" with milestones that span different sectors: energy efficiency; behavioral changes; electrification; renewables; hydrogen and hydrogen-based fuels; bioenergy; and carbon capture and storage (CCS). The agency says that all technologies needed on the path to 2030 already exist. But by 2050, nearly half the emissions cuts are expected to come from technologies that are still largely in the demonstration or prototype phase, such as advanced batteries and direct air CCS, and will require prioritization of and substantial increases in government R&D spending before 2030 to support clean energy innovation and leverage private investment. The National Academies of Sciences, Engineering and Medicine have called for the U.S. to triple federal investment in clean energy R&D and technology demonstration in order to meet a 2050 net-zero goal.[16]

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[15] *Examining the Pace of U.S. Carbon Reduction Goals Based on 2030 Goals*

[16] *The National Academies of Sciences, Engineering and Medicine. Accelerating Decarbonization of the U.S. Energy System (2021)*

PPL's Clean Energy Transition Strategy and Path to Net-Zero Carbon Emissions

PPL is developing a strategic framework with the goal of positioning the company to help advance a clean energy future within our service territories and across the broader United States. Our transition strategy is fundamentally centered around four key areas that we believe will enable us to advance new opportunities for the company and help deliver a net-zero economy by 2050:

- Decarbonize our generation.
- Decarbonize our non-generation operations.
- Advance research and development.
- Enable third-party decarbonization.

We view our path to net-zero emissions on a continuum, with a primary focus on eliminating our gross emissions, leveraging technology to remove emissions where they cannot be eliminated due to cost or reliability constraints, and finally, considering carbon offsets for any remaining emissions as the least-preferred option.

Our commitment to achieve net-zero carbon emissions by 2050 is backed by the actions that we are and will continue to take to support a low-carbon energy system that is affordable and reliable and provides the time needed for technology to advance. One clear example is our rigorous capital expenditure program that is based on identified projects designed to deliver long-term value for our stakeholders and align with our corporate strategy. As a result of PPL's strategic repositioning, we continue to evaluate additional capital investment opportunities. In the meantime, we plan to invest at least $1 billion in proceeds from the sale of WPD in additional regulated T&D capital investments through 2025 to maintain and improve grid resiliency and reliability, and support grid modernization.

Commitment: Decarbonize our generation

Goals:

- **Economically retire coal-fired generation.**
- **Advance clean power generation and leverage future technologies.**
- **Maintain reliability and affordability for our Kentucky customers and support state economic development.**

Advancing a cleaner energy future and reducing the largest source of PPL's direct emissions involves investing in renewable and non-emitting generation. The only fossil-fueled power plants PPL owns are in Kentucky, where LG&E and KU have plans to economically retire aging power plants and replace them with non-emitting generation. Based on the current retirement schedule, we expect our coal capacity to be reduced from just over 4,700 megawatts in 2020 to approximately 550 megawatts in 2050 (Figure 11). We believe that actions needed to further transition our generation offer PPL significant long-term opportunities for investment in new, non-emitting generation and clean energy technologies to help deliver value for our customers and shareowners. We will continue to develop plans to ensure that we can execute that transition in a manner that provides reliable and affordable power for our customers.

LG&E and KU are increasing solar generation through customer programs without increasing costs to non-participating customers. This includes offering a Green Tariff that enables renewables to be layered in through PPAs and a community solar share program. The PPAs to date total 225 megawatts of solar, and five of the eight 500-kilowatt Solar Share sections are complete.

Our 2021 Kentucky IRP addresses issues associated with the clean energy transition, including future load changes and the addition of new clean generation technologies. The IRP includes the retirement of nearly 2,000 megawatts of coal by 2036 and the addition of solar supported by storage, as well as natural gas simple cycle peaking plants, mainly for winter reliability. We are not building new coal generation, and our IRP base plan does not include plans for new combined-cycle gas facilities. We will continue to work with our state regulators and stakeholders as we develop additional plans and proposals, subject to regulatory approvals, in connection with our resource planning. We will submit our next IRP in 2024 that will cover a 15-year planning horizon through 2039. We expect that IRP to include additional non-emitting generation investment as we retire additional plants and address future capacity needs.

Figure 11: PPL's Kentucky Baseload Generation Resources

Power Plant	Unit	COD	Owned Capacity MW	Currently Projected End of Economic Useful Life (1)
Coal				
Mill Creek	1	1972	300	2024
E.W. Brown	3	1971	412	2028
Mill Creek	2	1974	297	2028
Ghent	1	1974	475	2034
Ghent	2	1977	485	2034
Ghent	3	1981	481	2037
Ghent	4	1984	478	2037
Mill Creek	3	1978	391	2039
Mill Creek	4	1982	477	2039
Trimble County	1	1990	370	2045
Trimble County	2	2011	549	2066
Natural Gas				
Cane Run (CCGT)	7	2015	662	2055
Total Baseload			5377	

(1) Per most recent deprection study filed in Case Nos. 2020-00349 and 2020-00350

Kentucky is a state rooted in manufacturing and energy development, and electricity costs are a key consideration for current and future economic development, including green energy development.[17] Kentucky has attracted over $10 billion of planned investments in the state in 2021 and we believe that there is opportunity for additional economic development growth in the state and commensurate load growth. Over the long-term, we will need a diverse and reliable generation mix that contains renewables and other clean, flexible energy resources to ensure that we can meet the electricity needs of our customers. PPL is investing in clean energy technology R&D, and LG&E and KU are providing leadership in demonstrating several clean energy technologies at the E.W. Brown Generating Station discussed in more detail below.

In addition, our current strategy involves responsibly investing in our unregulated renewable generation portfolio through Safari Energy. PPL's Safari Energy, LLC, subsidiary, continues to support the development of renewable energy in dozens of states across the U.S. Safari Energy has developed or acquired more than 500 commercial-scale solar projects since 2008. Since expanding its business model beyond building and selling solar facilities, the company has acquired more than 120 megawatts of solar generation that are operational as of October 2021. PPL is currently investing about $100 million annually in this business. We plan to continue to assess our unregulated clean energy generation strategy, including investment opportunities that fit within PPL's disciplined investment approach and risk tolerance.

Commitment: Decarbonize Our Non-Generation Operations

In addition to decarbonizing our generation portfolio, PPL's carbon emissions goal and clean energy transition strategy include decarbonizing other areas of our business by reducing company energy use, increasing electrification of fleet vehicles and reducing emissions associated with transmission and distribution equipment and gas distribution. The goals identified below are part of our plans to meet our corporate net-zero emissions by 2050 goal and are linked to operational performance. We intend to have similar goals for our future Rhode Island operations.

Goal: Electrify owned fleet vehicles.

Recognizing that the transportation sector has become the largest source of CO_2 emission in the U.S., we are strengthening our commitment to fleet electrification and have set new goals for transitioning our fleet. PPL's plans include converting light-duty vehicles from carbon-based fuels using a combination of fully electric vehicles or plug-in hybrids. For heavy-duty vehicles, electric lift technology uses battery power to operate the boom, bucket and lifts used by lineworkers, reducing the need for engine idling. This reduces fuel consumption and maintenance costs and minimizes job site noise. Fuel consumption is reduced by as much as a gallon of diesel fuel per hour of eliminated idling.

Goal: Reduce overall energy use for owned buildings.

PPL will undertake facilities planning to reduce emissions associated with our electric and gas use, including increasing renewables consumption for our owned buildings. We have already begun to identify opportunities to serve our energy needs through clean energy options. In Pennsylvania, we completed our first solar project at a PPL Electric facility, a 40-kilowatt solar array, to help meet our energy needs. We expect to install systems at additional service centers in the future. In Kentucky, a fully regulated state, reductions in building electricity use will help to reduce scope 1 emissions from our owned generation.

Goal: Assess operational improvements and investments necessary to maintain fugitive emissions rates at or below industry average across PPL's utilities.

We have reduced fugitive emissions associated with transmission and distribution equipment by 62% since 2010. PPL's operating companies continue to work to reduce sulfur hexafluoride (SF_6) greenhouse gas emissions through maintenance and equipment replacement. For example, PPL Electric has been using data analytics since 2015 to predict the failure rates of circuit breakers so that they can be replaced or repaired before SF_6 is released. This has resulted in top-decile performance for leak reduction, according to U.S. Environmental Protection Agency benchmark data. PPL Electric is in the implementation stage of replacing SF_6 breakers with vacuum breakers on 69kV transformers. LG&E and KU are performing trials with vacuum breakers as an alternative to utilization of SF_6 breakers. Vacuum technology uses dry air as insulation material and has been highly reliable in tests.

62%

Reduction in fugitive emissions associated with transmission and distribution equipment since 2010.

LG&E has reduced scope 1 fugitive emissions from gas distribution operations by 37% since 2016. These emissions reductions have been realized through inspection programs and replacement of steel customer service lines and aging natural gas transmission lines. Through 2020, LG&E has replaced, removed or verified about 8,300 customer services lines and removed 3,300 inactive steel services. LG&E implemented a Transmission Modernization program to replace approximately 15.5 miles of transmission pipeline in Jefferson County. Through 2020, approximately eight miles had been installed with over three miles placed into service. It is anticipated the project will be largely complete by the end of 2021. LG&E's Lost and Unaccounted for Gas as reported on our Gas Distribution Annual Report filed with Pipeline and Hazardous Materials Safety Administration was 1.1% for the year ending June 30, 2020, an amount within the industry average.

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[17] *Green energy takes hold in unlikely places with Ford project (September 28, 2021): https://apnews.com/article/business-technology-kentucky-electric-vehicles-tennessee-6b515f5e4dcf89607a6c671bc9d31a68*

Commitment: Further Research and Development

Achieving net-zero carbon emissions requires advances in clean energy technologies and systems that can be delivered safely, reliably and affordably for those we serve. As we support a clean energy transition, we also recognize that we need to invest in innovation to address changing customer preferences, drive efficiencies in our business and enable broad access to clean energy technologies. With this in mind, we continue to invest in clean energy research and development to enable us to meet our net-zero-by-2050 goal while driving value for our customers and shareowners.

Goal: Advance new technologies through research, development and innovation in partnership with industry and research institutions.

In early 2021, PPL expanded its efforts to advance clean energy technologies by joining Energy Impact Partners' (EIP) global investment platform, which brings together leading companies and entrepreneurs worldwide to foster innovation toward a sustainable energy future. PPL has committed to invest up to $50 million across EIP's investment platform aimed at accelerating the shift to a low-carbon future and driving commercial-scale solutions needed to deliver deep, economy-wide decarbonization. Collaboration with EIP is expected to provide PPL greater visibility into emerging technologies that can be leveraged to advance the clean energy transition.

PPL is deeply involved in industry efforts focused on advancing research in several key technology areas: advanced dispatchable renewables and power electronics; long-duration energy storage and advanced demand efficiency; zero-carbon fuels (e.g., hydrogen); advanced nuclear energy; and carbon capture, utilization and storage. We are also promoting supportive policies for technology deployment through EEI's Carbon-Free Technology Initiative (CFTI), a coalition of environmental and technology-focused non-governmental organizations focused on implementation of federal policies that can help ensure the commercial availability of affordable, carbon-free, 24/7 power technology by the early 2030s.

As an anchor member in the EPRI-Gas Technology Institute (GTI) five-year Low-Carbon Resources Initiative (LCRI), PPL is committed to helping accelerate research and development of low-carbon and zero-carbon technologies. PPL's CEO is helping to lead this effort as chair of the LCRI Board Working Group.

The LCRI is a collaborative focused on identifying, developing and demonstrating affordable pathways to economy-wide decarbonization. This initiative is pursuing fundamental advances in a variety of low-carbon electric generation technologies and low-carbon energy carriers, such as advanced nuclear, carbon capture, utilization and sequestration (CCUS), hydrogen, ammonia, synthetic fuels and biofuels. This also includes assessing low-carbon pathways for producing, transporting and storing these energy carriers, as well as opportunities to use them in power generation, transportation and other applications.

PPL's operating companies also continue to support a variety of separate research and development activities. LG&E and KU's energy storage demonstration site in partnership with EPRI, is the first and largest utility-scale energy storage system in Kentucky. The battery is co-located with LG&E and KU's 10 megawatt solar plant, allowing the utilities to explore how the systems can operate together, a critical tool for understanding how intermittent renewable generation best fits into the company's generation portfolio and how batteries can improve site performance and reliability. LG&E and KU are also partnering with the University of Kentucky Power and Energy Institute of Kentucky (PEIK) on the integration of intermittent renewable generation.

PPL Electric's Keystone Solar Future Project, a project in partnership with the U.S. Department of Energy, industry and academia, has led to development of a dynamic distribution platform that has been recognized as innovative and industry-leading by the Smart Electric Power Alliance (SEPA), which named PPL Electric Utilities as the 2019 SEPA Power Players Investor-Owned Utility of the Year. Other activities include research into energy storage for the electric transmission system, the integration of DERs and electrification.

> *PPL believes that an all-of-the above approach to clean energy technology is needed to help deliver a sustainable clean energy transition that supports energy reliability, resilience and economic growth.*

LG&E and KU, in partnership with the University of Kentucky's Center for Applied Research (CAER), are evaluating the use of carbon capture technology. CAER began its CO_2 program in 2006 with seed funding from LG&E and KU and has since established itself as a global leader in developing CO_2 capture technology. Since 2006, LG&E and KU have directly invested more than $4 million in CAER's decarbonization research. In 2014, CAER constructed a pilot-scale carbon capture unit at LG&E and KU's E.W. Brown Generating Station, which is one of a few at power plants in the U.S. with an operating carbon capture system. Using the existing CO_2 capture system, CAER plans to chemically alter the plant's flue gas to replicate the characteristics of a natural gas combined cycle plant. If successful, the technology could be demonstrated at LG&E and KU's Cane Run Station NGCC plant, continuing leading research, development and demonstration of this technology. Research from the natural gas CCS project will also support a planned bench-scale direct air capture system capable of 90% CO_2 capture, resulting in negative emissions, and produce 99.9% purity hydrogen gas. LCRI and LG&E and KU are among the partners for this planned research.

PPL believes that an all-of-the above approach to clean energy technology is needed to help deliver a sustainable clean energy transition that supports energy reliability, resilience and economic growth. Accordingly, PPL will continue to invest in advancing a full range of technologies that will help to advance our clean energy transition strategy.

Commitment: Enable Third-Party Decarbonization

We recognize the value of the energy grid in supporting the clean energy transition and economywide decarbonization. We will need to advance a clean energy delivery strategy that drives innovation, efficiency and resiliency.

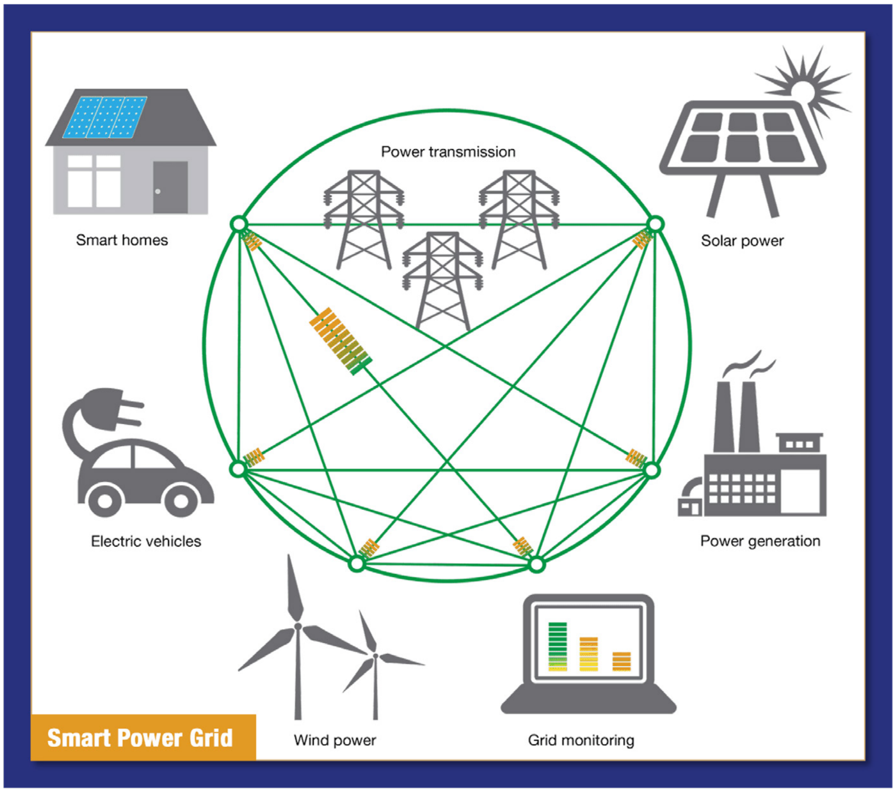
Goal: Position the grid as an enabler for clean energy resources and leverage leading performance across our utilities.

Our electric grid will need to support increased electrification of the economy and transportation, large-scale connection of DERs to distribution networks and the transmission of utility scale renewable energy to local communities and businesses. PPL has developed an advanced, resilient grid that's ready to assimilate renewable energy safely, reliably and cost-effectively by reducing the need for upgrades to accommodate new connections (Figure 12). We believe that additional investments in smart grid technology and the construction of new transmission to accommodate and deliver renewables present future investment opportunities for PPL and value for our customers. PPL will leverage our experience in Pennsylvania and the technology we have developed to deliver similar benefits to customers in Kentucky, where LG&E and KU recently received approval to deploy advance metering, and eventually in Rhode Island, where the state has adopted a goal to achieve net-zero economy wide carbon emissions by 2050.

As referenced earlier, PPL Electric has developed an automated electric distribution network designed to not only strengthen resiliency in the face of severe weather, but also pave the way to integrate increased DERs reliably and efficiently. PPL Electric's distributed energy resource management system (DERMS) enables real-time monitoring and management of renewable resources connected to the grid, including behind-the-meter resources. DERMS allows our operation system to mitigate any power quality issues as a result of renewable resources, in addition to increasing the ability of our grid to host more renewable resources without the need to make grid investments.

While much of the transmission infrastructure in the U.S. is aging, PPL Electric Utilities has made investments in the transmission system to address aging infrastructure, increase the capacity and efficiency of transmission line usage[18], and integrate new technologies. This allows us to significantly lower our long-term maintenance costs and better position us for accommodating renewable energy. Our large generator interconnection requests have increased by more than eight times since 2017, with about 95% of all requests being carbon-free resources. Because these connections are being made at the transmission-level, our team must complete feasibility studies for the regional transmission operator. These studies are very involved, yet even with the large spike, our team has a 100% on-time completion rate for all necessary studies. We are also sharing the lessons we've learned and successes we have achieved with a PJM Interconnection task force to help improve the process and reduce the backlog of requests within PJM.

Figure 12: Reimagining Energy Delivery



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[18] *Public Utilities Fortnightly has named PPL Electric Utilities as a Top Innovator for 2021 for its industry-leading use of dynamic line rating technology on its transmission lines to increase electricity delivered over existing transmission lines.*

New transmission capacity on the scale necessary to decarbonize the economy will need to be supported by regulatory policies that facilitate permitting, siting and financing of this critical infrastructure. PPL recently acquired a small ownership interest in SOO Green, a 350-mile underground transmission project that seeks to connect the MISO and PJM power markets to support growing demand for clean energy. SOO Green seeks to tackle siting, permitting and other challenges to quickly and cost-effectively building transmission by developing high-voltage transmission lines underground along major rail cooridors. We will lend our capabilities and transmission expertise to help support the success of this project, and we will gain valuable insight into this innovative approach.

Our gas distribution infrastructure will need to support continued demand for gas where full electrification of heating and industrial and commercial operations may not make sense, and in the future accommodate the addition of alternative fuels to reduce the carbon footprint of the gas being delivered. PPL will consider development of energy system plans that address both electric and gas distribution operations to help drive efficiencies, maintain critical infrastructure and help preserve options for customers. This system-wide planning approach will be particularly important for Rhode Island as we prepare to partner with the state in meeting clean energy goals.

Goal: Support adoption of electric vehicles through expansion of electric vehicle charging.

PPL companies are supporting electric vehicle adoption through programs that improve accessibility to charging infrastructure and connect customers with tools and information to make informed choices. Electrification of the transportation sector not only reduces CO_2 emissions but is expected to contribute to increased electricity sales and the opportunity for investment in make-ready work for vehicle chargers.

In September 2021, PPL's utilities joined the Electric Highway Coalition, a partnership of 17 U.S. utilities established to support the development of a seamless network of rapid electric vehicle charging stations connecting major highway systems. The coalition's focus includes optimizing the placement of infrastructure and complementing existing travel corridor fast charging sites.

LG&E and KU have deployed 20 level 2 medium-speed chargers in public locations that they own, operate and maintain. Looking forward, the company also plans to deploy up to eight additional fast-charging stations along major Kentucky highway corridors, with four of the eight stations subject to state funding. LG&E and KU are in the early stages of a system study that outlines capacity in areas on the utilties' system that are well suited for fast chargers. LG&E and KU are also offering customer-facing programs to encourage EV adoption, including a vehicle charging program that provides cost-effective leases for customers to host a charging station at their locations. Customers can shop and compare EVs and calculate costs savings over time through an online marketplace available on LG&E and KU's website.

PPL Electric is working with SEPA to develop a long-term EV charging strategy for its 29-county service territory. PPL Electric is not permitted to own EV chargers; however, the utility is using data analytics to determine the most advantageous and likely fast charger locations and developing a make-ready process to support installation of EV chargers. Through its interconnection process, PPL Electric is currently coordinating the connection of 29 new high-speed chargers.

Conclusion

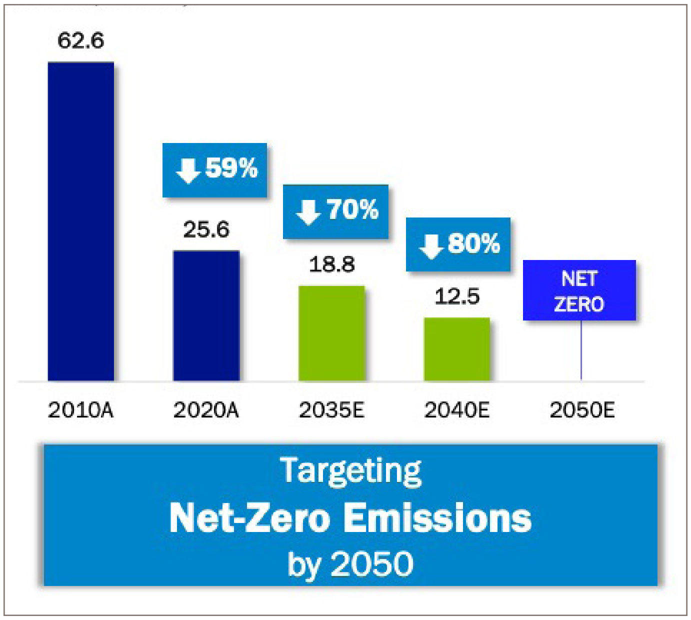
2021 has been a transformational year for PPL. We strategically repositioned the company to be a high-performing U.S.-focused energy company. We delivered award-winning service at competitive prices and were recognized for our innovative, technology-driven efforts to make our energy grid smarter, cleaner and more resilient. We invested more in clean energy technology R&D than ever before, with tens of millions of dollars committed to an innovative early-stage investment platform. We are partnering and leading efforts to bring about the commercial deployment of technologies that we believe will advance our efforts to achieve net-zero emissions from our operations and support our customers, investors, states and communities' desire for affordable, reliable and clean energy. We do not believe that these attributes are mutually exclusive. Our analysis conducted as part of this report and through our generation IRP demonstrates what may be possible under various scenarios. We are confident that a focused, deliberate effort to be pursued over the next decade will put us on a path to achieve our clean energy goals and deliver on our strategic commitment to advance a cleaner energy future.

About this report

The goals and projects described in this report are aspirational; as such, no guarantees or promises are made that these goals and projects will be met or successfully executed. Furthermore, this report contains data, statistics and metrics that are non-audited estimates, not prepared in accordance with generally accepted accounting principles (GAAP), continue to evolve and may be based on assumptions believed to be reasonable at the time of preparation, but should not be considered guarantees and are subject to future revision.

Metrics and Targets

Figure 13: PPL 2050 Net-Zero Emissions Goal



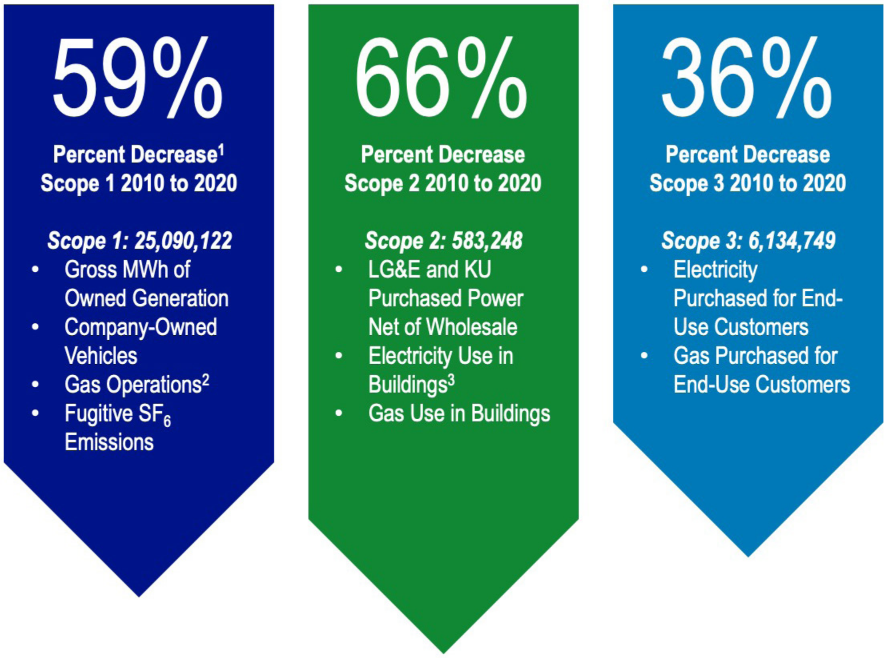
PPL provides an annual greenhouse gas inventory in our Corporate Sustainability Report with five years of emissions data. Categories of emissions cover scopes 1, 2 and 3 CO_2e emissions, including owned generation, fleet vehicles, SF_6 used in electric transmission and distribution operations, methane emissions from natural gas operations, and purchased gas and electric. Carbon intensity is also reported on a revenue and generation basis.

On an annual basis, we report progress toward our carbon emissions reduction goal. Our 2050 goal covers all scope 1 and 2 CO_2e emissions except for methane emissions from our natural gas distribution operations (scope 1), which totaled just over 22,000 metric tons of CO_2e in 2020. PPL classifies LG&E and KU's purchased power net of wholesale as a scope 2 emission, which is also included in our goal. We believe that greenhouse gas accounting protocols related to purchased power for end-use customers (not used by or otherwise combusted by the utility) would also support the reporting of these emissions as scope 3.

Our current fleet electrification goals are aimed at collectively reducing carbon emissions from our fleet vehicles by 5,000 metric tons by 2030, approximately a 20% reduction from 2020 levels. This goal is expected to be replaced by more ambitious fleet vehicle goals in the near future, and we anticipate reporting progress against new goals going forward.

Emissions associated with our purchased electricity in Pennsylvania and gas in Kentucky are relevant to core operations of our transmission and distribution businesses, and therefore, we believe that we collect and report these scope 3 emissions with a high degree of accuracy. However, PPL's delivery companies have limited discretion over the resource mix of this purchased power, which is subject to state portfolio mandates and approval of direct costs passed through to customers. We recently began collecting data associated with employee commuting and travel and will also include these scope 3 emissions in our 2021 reporting year sustainability reporting.

Figure 14: 2020 CO_2e emissions (metric tons)



59%

Percent Decrease[1]
Scope 1 2010 to 2020

Scope 1: 25,090,122
- Gross MWh of Owned Generation
- Company-Owned Vehicles
- Gas Operations[2]
- Fugitive SF_6 Emissions

66%

Percent Decrease
Scope 2 2010 to 2020

Scope 2: 583,248
- LG&E and KU Purchased Power Net of Wholesale
- Electricity Use in Buildings[3]
- Gas Use in Buildings

36%

Percent Decrease
Scope 3 2010 to 2020

Scope 3: 6,134,749
- Electricity Purchased for End-Use Customers
- Gas Purchased for End-Use Customers

[1] *2010 Scope 1 plant emissions is the only data point that includes PPL Energy Supply, LLC.*
[2] *Gas Operations are not included in the net-zero emissions goal. 2010 baseline data is estimated.*
[3] *LG&E and KU emissions captured in Scope 1 Gross MWh.*

Appendix

Task Force on Climate-Related Financial Disclosures Index

Topic	Recommended Disclosure	PPL's Response Mapping
Governance		
Disclose the organization's governance around climate-related risks and opportunities.	Describe the board's oversight of climate-related risks and opportunities.	Page 9
	Describe management's role in assessing and managing climate-related risks and opportunities	Page 10
Strategy		
Disclose the actual and potential impacts of climate-related risks and opportunities on the organization's businesses, strategy, and financial planning where such information is material.	Describe the climate-related risks and opportunities the organization has identified over the short, medium and long term.	Pages 30-34
	Describe the impact of climate-related risks and opportunities on the organization's businesses, strategy and financial planning.	Page 13
	Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.	Pages 23, 29
Risk Management		
Disclose how the organization identifies, assesses, and manages climate-related risks.	Describe the organization's processes for identifying and assessing climate-related risks.	Page 9
	Describe the organization's processes for managing climate-related risks.	Page 13
	Describe how processes for identifying, assessing and managing climate-related risks are integrated into the organization's overall risk management.	Pages 9, 13
Metrics and Targets		
Disclose the metrics and targets used to assess and manage relevant climate-related risks and opportunities where such information is material.	Disclose the metrics used by the organization to assess climate-related risks and opportunities in line with its strategy and risk management process.	Pages 13, 23, 29
	Disclose Scope 1, Scope 2, and, if appropriate, Scope 3 greenhouse gas (GHG) emissions, and the related risks.	Pages 29 and 31-34
	Describe the targets used by the organization to manage climate-related risks and opportunities and performance against targets.	Page 29

Energy Group Metrics and additional disclosures are available our sustainability disclosure website.

Table 1: Potential Physical Risks and Response

Climate Risk	Asset Category	Asset Type	Potential Impact	Risk Mitigation
High Winds	Generation	All	Damage to power plant infrastructure	Engineering evaluation of facilities and structural upgrades
		Solar	Increased dust and debris on solar panels, reducing output or damaging racking. Potential impact damage from blowing debris.	More frequent inspections
	Electric Transmission & Distribution	Power lines and poles	Damage to equipment, derating or knocking generation offline, and more frequent power outages due to downed trees and limbs	• System hardening, including stronger poles and wires • Vegetation management • Increased automation technology to reroute power • New power lines and substations to provide flexibility and redundancy
	Gas Distribution	Gas Storage & Distribution	Damage to gas storage and distribution infrastructure	Engineering evaluation of facilities, including wind consideration for structural upgrades
			Loss of power	Installation of back-up generation
Extreme Cold	Generation	All	Frozen equipment, sensing lines, water lines and valves disrupting plant operations	• Enclosures for exposed sensitive equipment and systems • Expanded heat trace and insulation programs • Expanded cold weather procedures
		Fossil	Frozen coal pile and fuel supply issues and related generation derates	Implement enhanced inventory management (pile management; delivery strategies; keep the system operating to mitigate freezing and bridging; direct unloading of fresh coal)
		Solar	Solar trackers and other infrastructure may be damaged that can reduce output	More frequent inspections and as needed sweep off snow and/or de-ice panels
	Electric Transmission & Distribution	All	Damage due to severe icing on electrical equipment and downed trees and limbs,leading to extended power outages	• System hardening, including stronger poles and wires • Vegetation management • Increased smart grid technology to reroute power • New power lines and substations to provide flexibility and redundancy
	Gas Distribution	All	Frozen equipment, sensing lines, water lines and valves disrupting gas system operations	• Enclosures for exposed sensitive equipment and systems • Expanded heat trace and insulation programs • Expanded utilization of catalytic heaters • Enhanced alarm systems • Completed bare steel and cast-iron main piping replacements

Climate Risk	Asset Category	Asset Type	Potential Impact	Risk Mitigation
Precipitation	Generation	All	Damage to equipment, changes in operations and potential loss of facilities	Engineering evaluation of facilities and water resiliency improvements
		All	Reduced access due to flooding	Rerouting traffic and alternative access to equipment
		Fossil	Increased non-permitted discharges as a result of flooding	• Expanding and maintaining overflow and drainage paths • Enhancing flood protection systems
			Wet coal piles and fuel and reagent delivery disruptions and related generation derates	Implement enhanced inventory management (pile management for increased sheet flow; delivery strategies; direct unloading of fresh coal)
		Solar	Positive effects from precipitation washing panels. Reduced output from residue and scale build-up. Reduced output from ice and snow cover on solar panels.	More frequent inspections and cleanings
	Electric Transmission & Distribution	All	Damage to equipment, loss of facilities, and/or reduced access to facilities due to flooding, slowing power restoration	Evaluation of mitigation for critical equipment and substations from flood-prone areas
			Damage due to severe icing on electrical equipment and downed trees and limbs, leading to extended power outages	• System hardening, including stronger poles and wires • Vegetation management • Increased automation technology to reroute power • New power lines and substations to provide flexibility and redundancy
	Gas Distribution	All	Damage to equipment, loss of facilities, and/or reduced access to facilities due to flooding	• Engineering evaluation of facilities and perform water resiliency testing as applicable • Evaluation of mitigation for critical equipment from flood-prone areas • Completed bare steel and cast-iron main piping replacements
Extreme Heat	Generation	Fossil	Reduction in plant efficiency and available generation capacity due to higher ambient air temperatures and high coolant temperatures	• Inlet air cooling for natural gas units • Enhanced for cooling system infrastructure of coal units
			Potential physical damage if temperature thresholds are exceeded, forcing curtailment to avoid a safety hazard	Expanded equipment redundancy and critical spares
			Power plant components may need to be replaced more frequently	Expanded equipment redundancy and critical spares
			Increased risk of exceeding thermal discharge limits	Enhanced cooling system infrastructure
		Solar	Reduced efficiency and output if temperatures exceed ratings	Enhanced cooling system infrastructure
	Electric Transmission & Distribution	Transformers	De-rating, increased load, decreased capacity, decreased operational flexibility, increased maintenance, accelerated aging, loss of equipment life	• Pumps and fans for substation cooling • Real time and daily performance monitoring • Remote adjustments to optimize substation operations • New and expanded substations to provide flexibility and redundancy
		Power lines	De-rating and reduction in available transmission capacity	• Annual transmission planning and load forecasting, inclusive of weather factors. • Vegetation management. Increased automation to reroute power. • New power lines to provide flexibility and redundancy

Table 2: Potential Transition Risks and Response

Risk Type	Drivers	Potential Impact	Risk Mitigation and Opportunity Actions
Regulation, Policy	• Carbon regulation • Expanded renewable energy regulation • Mandates on existing products and services • Ownership limitations • Permitting and siting challenges • Static ratemaking mechanisms	• Uncertain or poorly constructed regulatory policy can lead to compliance challenges, resource constraints, unnecessary costs for consumers and premature retirement of viable energy assets. • Volatility in renewable energy standards and associated credit markets due to legislative or regulatory intervention. • Legislative limitations on utility ownership of renewables and other generation sources in restructured states limit the extent of activities those companies may engage in to support the clean energy transition. • Delays in permitting and siting transmission and renewable energy infrastructure due to land use concerns and lack of agency co-ordination, as well as environmental justice considerations. • Traditional ratemaking structures may constrain utilities seeking innovative solutions to incorporate new technologies, services, policies and market participants.	• Proactive engagement and advocacy with policymakers, regulators and community leaders; early stakeholder outreach to potentially impacted communities. • Experience operating in a dynamic regulatory environment in all its geographic locations and carefully monitors evolving and emerging legislation and regulations at the local, state and federal levels. • Greater electrification of the economy to reduce carbon, in particular electrification of cars and heating, could support increased electricity sales and require additional investments in distribution networks. This could also require additional investment in generation in Kentucky to meet increased load. • Significant investments in smart grid technology and the flexibility of delivery networks to accommodate changing customer preferences and needs to enhance the integration of DERs provides the opportunity for wires-only companies to take on an expanded role in actively managing distribution networks through both network and non-network solutions, products and services. • Energy system planning across assets to maximize efficiencies. • Leverage alternative forms of ratemaking to support climate change mitigation and adaptation-related activities, renewable energy expansion, energy efficiency and conservation, and electrification. Further, utilize these mechanisms to improve financial and environmental sustainability.
Market	• Changing customer behavior • Evolving technologies and policies allowing new entrants into the market • Increase in distributed energy resources • Regulatory changes impacting wholesale and retail markets	• Decreased revenues due to reduced demand for products and services. • Competitive clean energy solutions can erode regulated rate base and diminish relationship with customer. • Increases in distributed energy resources and private renewable energy could pose a reliability challenge to delivery networks if not incorporated and managed appropriately. Such an increase could make it more difficult to monitor and adequately provide necessary 24/7 generation and to manage volatility in demand for power. • Changes in market access, including how market participants aggregate and operate, can cause market volatility and down-stream distribution system operation issues.	• Enabling the deployment of renewables and distributed energy resources through direct investments and actively finding ways to provide clean energy options to customers. • Energy grid modernization to enable reliable integration of more renewable and low-carbon energy sources, enhance grid resiliency and reduce emissions. • Disciplined expansion of unregulated renewable and distributed energy investments, including solar and energy storage. • Solutions, driven by customer demand and favorable policies • Development and implementation of expanded distribution system operation models (e.g., DSO), and customer DER integration platforms and portals. • Improved coordination between RTOs/ISOs, utility transmission operations, utility distribution operations and behind-the-meter generation.

Risk Type	Drivers	Potential Impact	Risk Mitigation and Opportunity Actions
Reputation	• Growing public concern over climate change • Shifts in consumer preference • Increased costs resulting from clean energy transition • Volatile wholesale energy markets	• Reduced access to capital due to coal exposure. • Increased volatility in fossil fuel costs (e.g., natural gas) leading to volatile wholesale energy prices and associated customer generation and gas distribution rates impacting moderate and low-income customer bills. • Decreased customer satisfaction. • Regulatory pressure on allowed returns. • Reduced pool of insurance carriers due to carriers' concern on coal exposure.	• Risk assessments factor stakeholder input into long-term investment decisions. • Increasing renewable and non-carbon emitting assets and economically retiring coal fired-generation; driving down carbon emissions. • Providing affordable clean energy options and facilitating the interconnection of customer DER. • Enabling greater electrification of the economy, in particular the widespread adoption of electric vehicles and the electrification of industries previously powered by fossil fuels, could support increased electricity sales and require additional investments in T&D networks. • Provide new or alternative rate options for customers to enable customers to choose the best options that meet their socio-economic goals and objectives.
Technology	• Lack of commercial availability of deep decarbonization technologies • Costs to transition to clean energy technologies • Development of new systems to manage customer DER integration, improve T&D operations, and improve the customer experience	• Reduces clean generation options available for transition. • Negative reliability and affordability impacts. • Delays in economy-wide decarbonization. • Need to develop systems from the bottom-up, with few 'off-the-shelf' solutions available to utilize.	• Deploying resources to support R&D and commercialization of clean energy technologies for generation and gas distribution. • Supporting technology-neutral investments in R&D to expand availability of non-emitting resources. • Partnering with academia and industry in demonstration of clean energy technologies, including CCS and battery storage. • Leverage State and Federal funding opportunities to invest in new and innovative technological solutions.

Figure 1: ERM Process

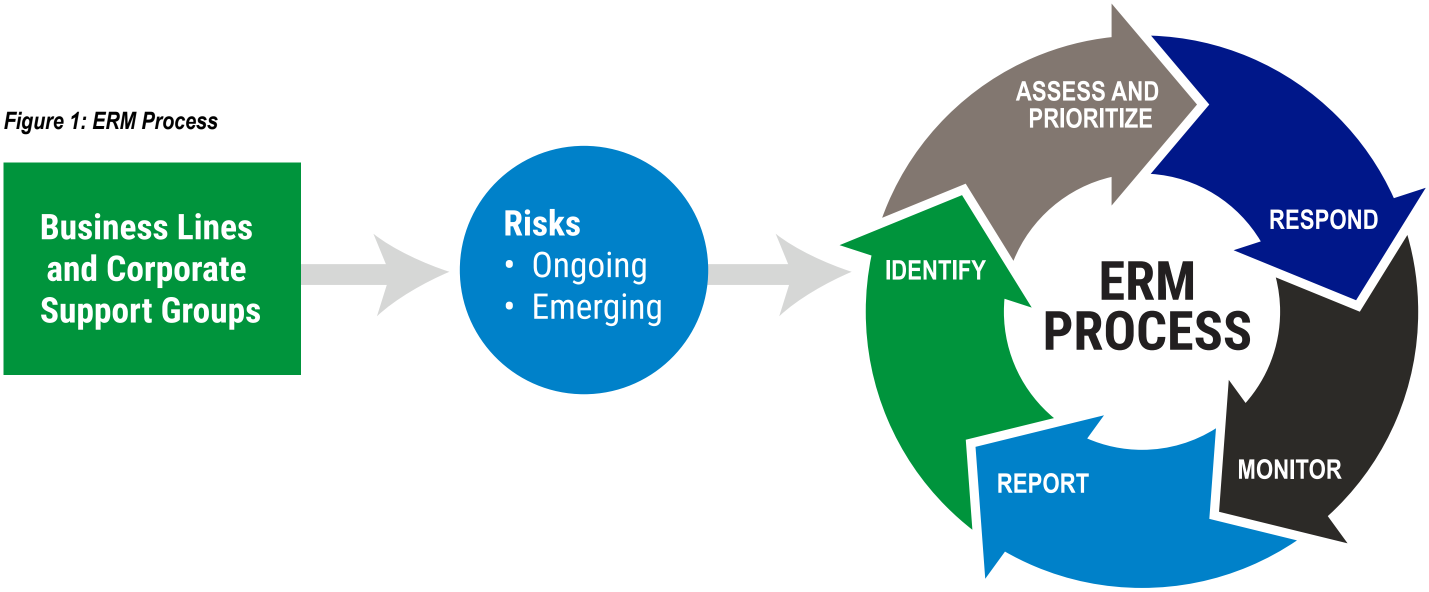


Figure 2: Board Committee Oversight of Climate-Related Issues

Governance and Nominating Committee	Oversees the company's sustainability-related policies and practices; reviews key corporate sustainability disclosures and receives regular sustainability and ESG reports, including discussion of key climate and clean energy trends, risks and opportunities.
Audit Committee	Receives quarterly reports on enterprise risk management. The Audit Committee regularly reviews risk management activities, including issues related to the transition of the utility sector, such as sustainability and climate-related issues, as well as activities related to the company's financial statements and disclosures, and certain legal and compliance matters.
Finance Committee	Annually reviews and approves a multi-year business plan and capital expenditure plan. The Finance Committee also approves major capital financing, acquisitions and divestitures. Climate-related issues are addressed in the business and capital plans.
Compensation Committee	Reviews and approves annually the compensation structure, including ESG goals and objectives, for the Company's executive officers.

Figure 3: Ensuring Reliable Generation Operations

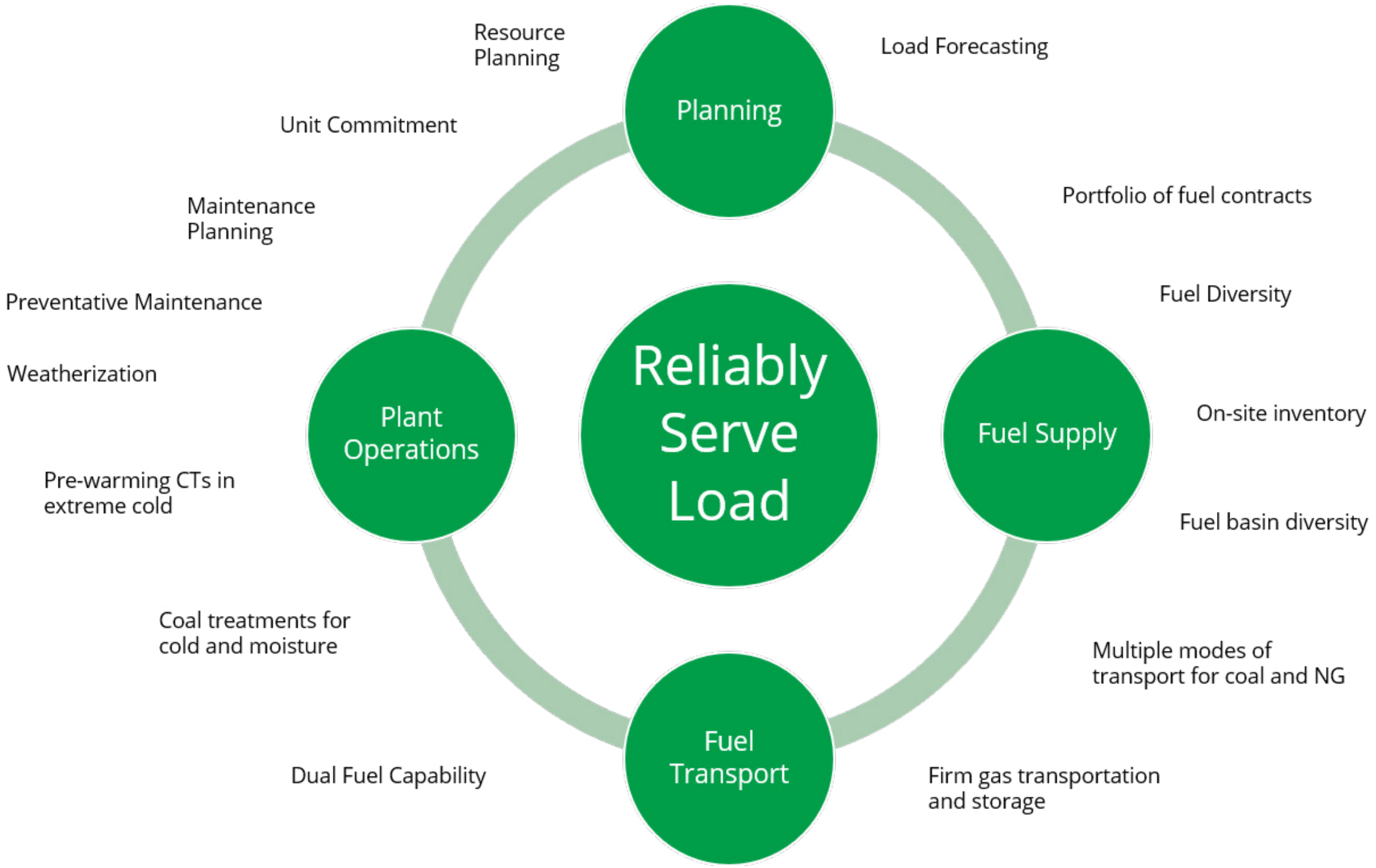
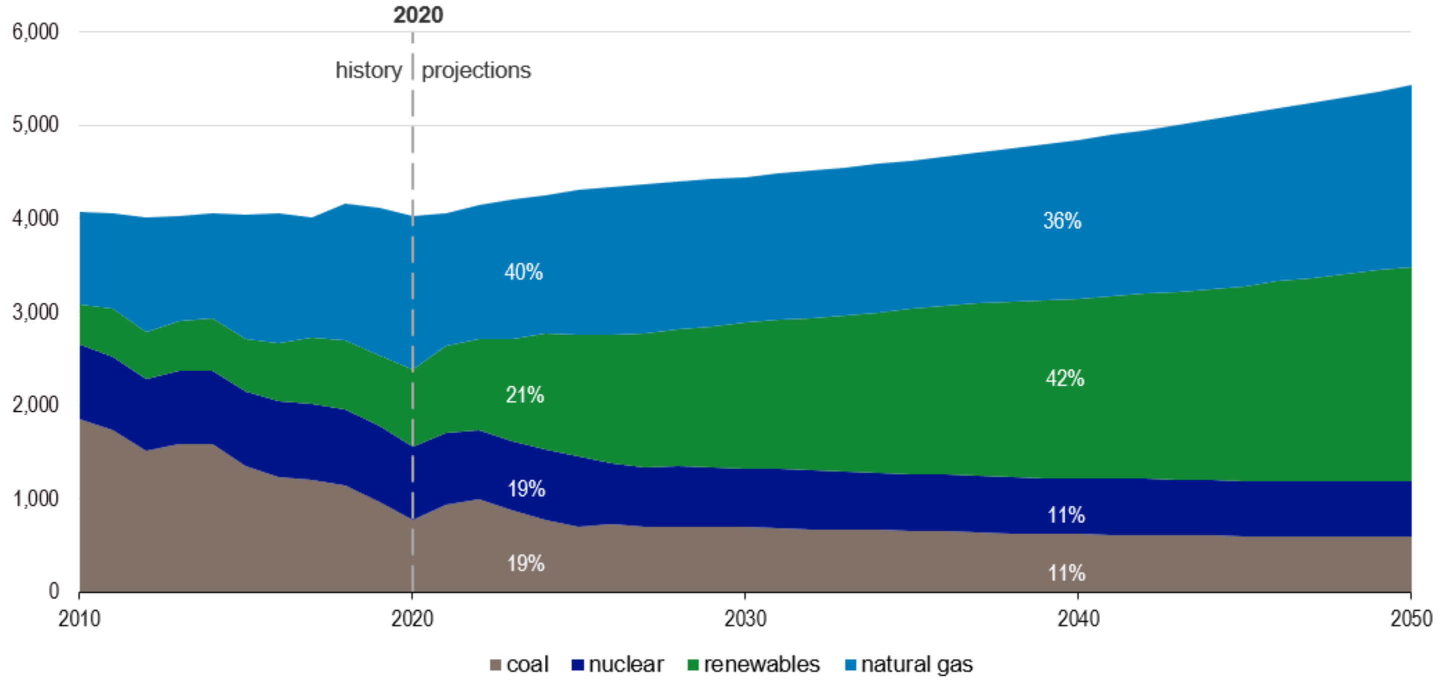


Figure 4: U.S. Electricity Generation from Selected Fuels (2010-2050)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2021 (AEO2021)

Figure 5: Energy Requirements

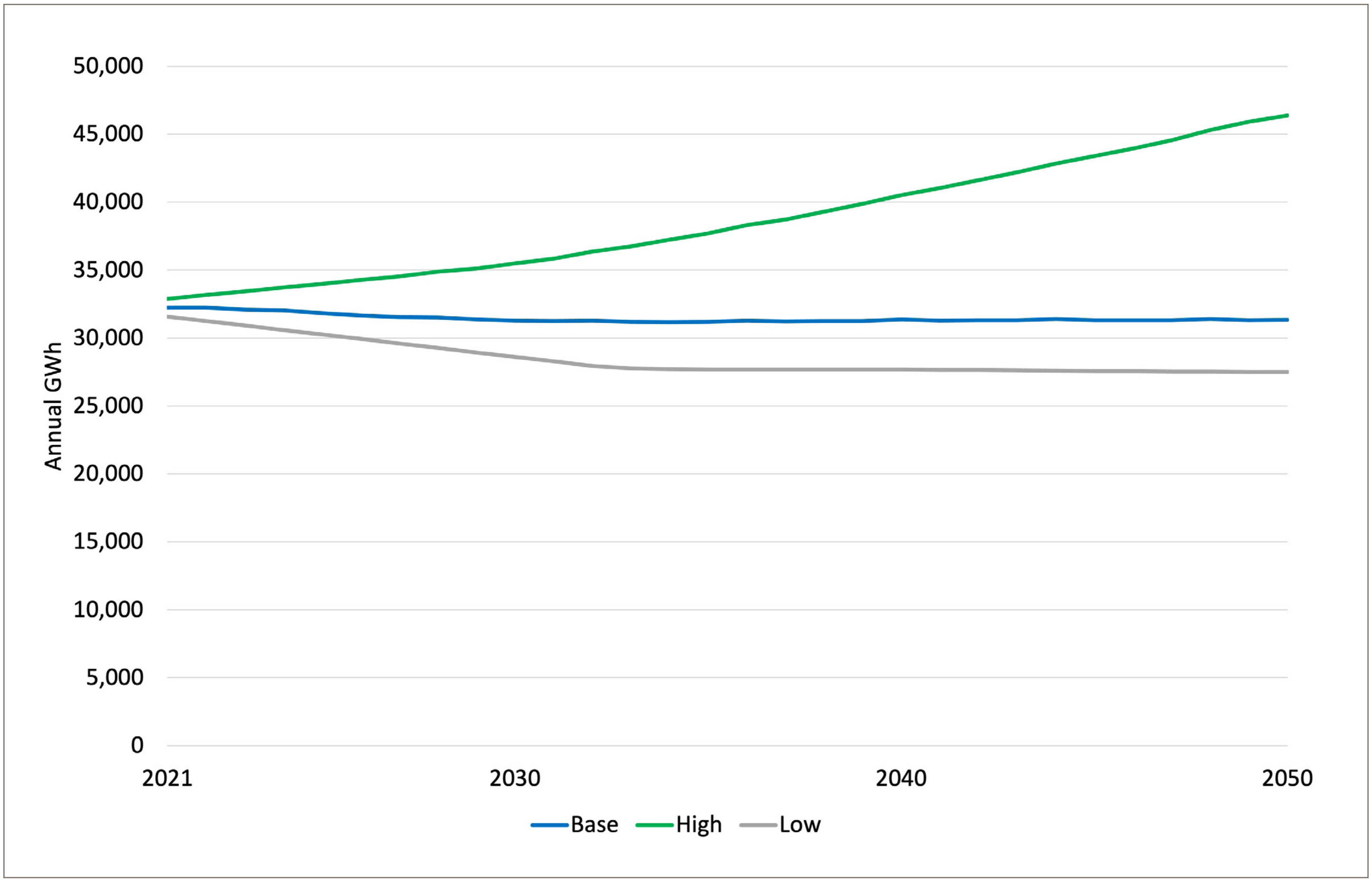


Figure 6: Number of Electric Vehicles

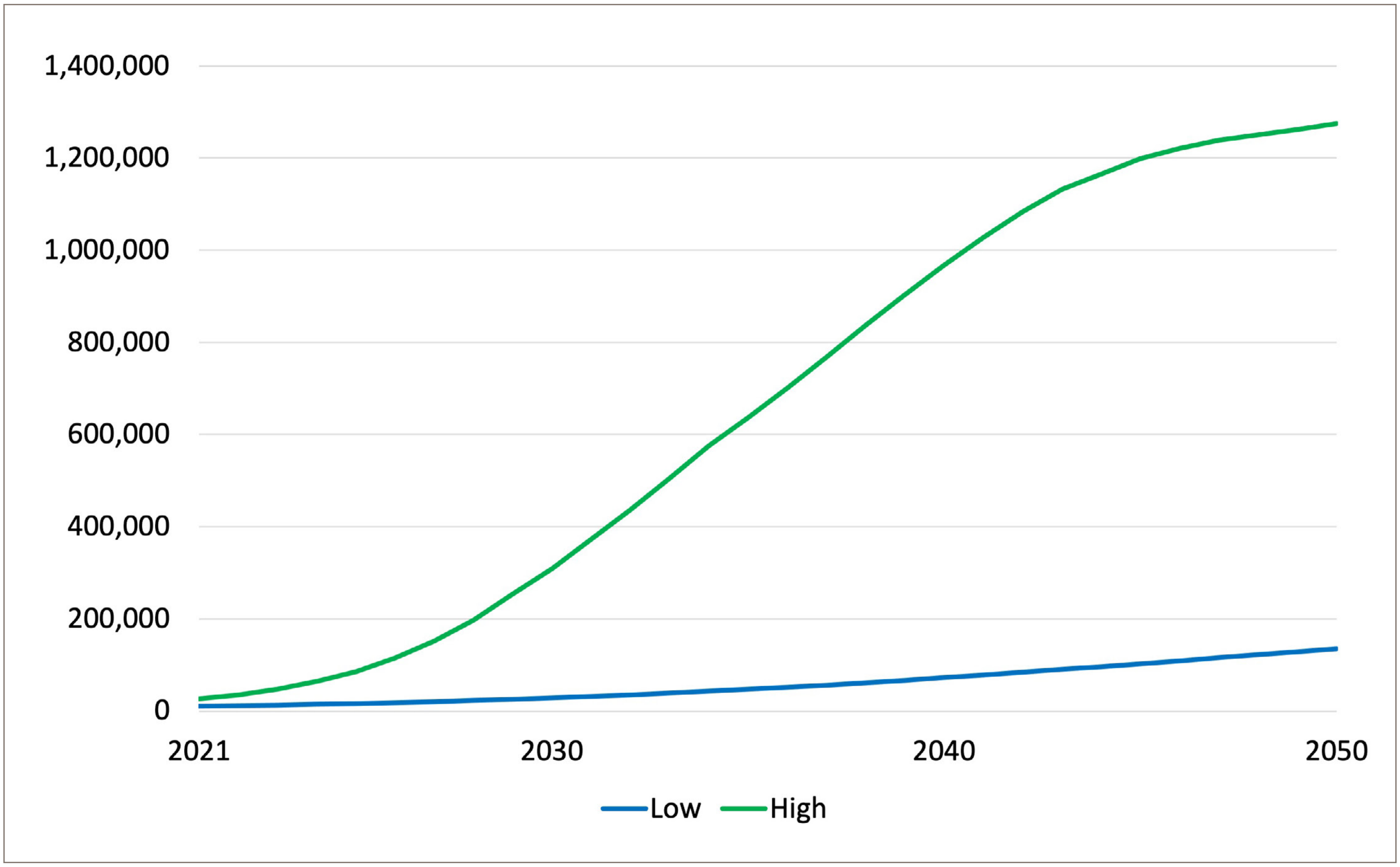


Figure 7: Distributed Solar Installed Capacity

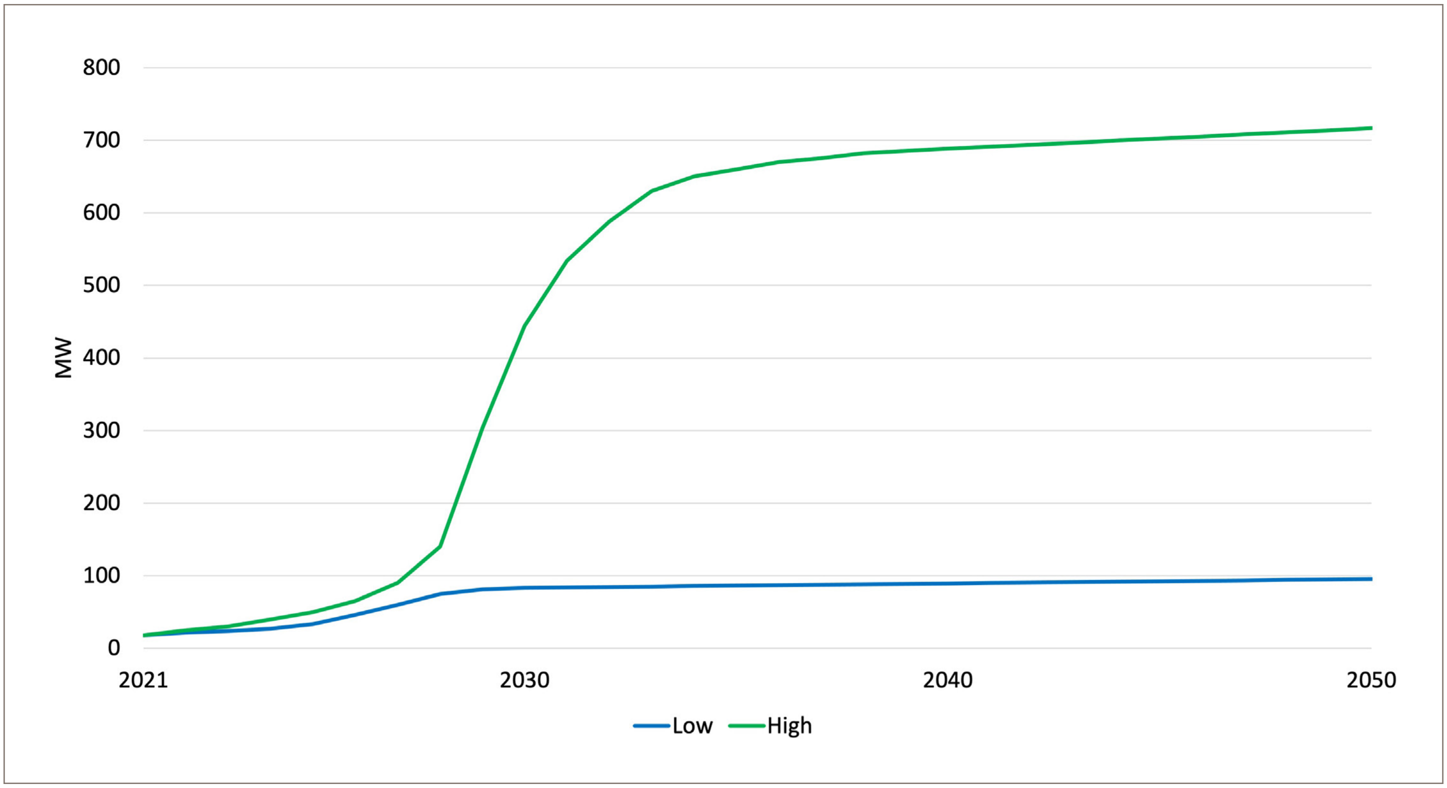


Figure 8: Comparison of Scenarios

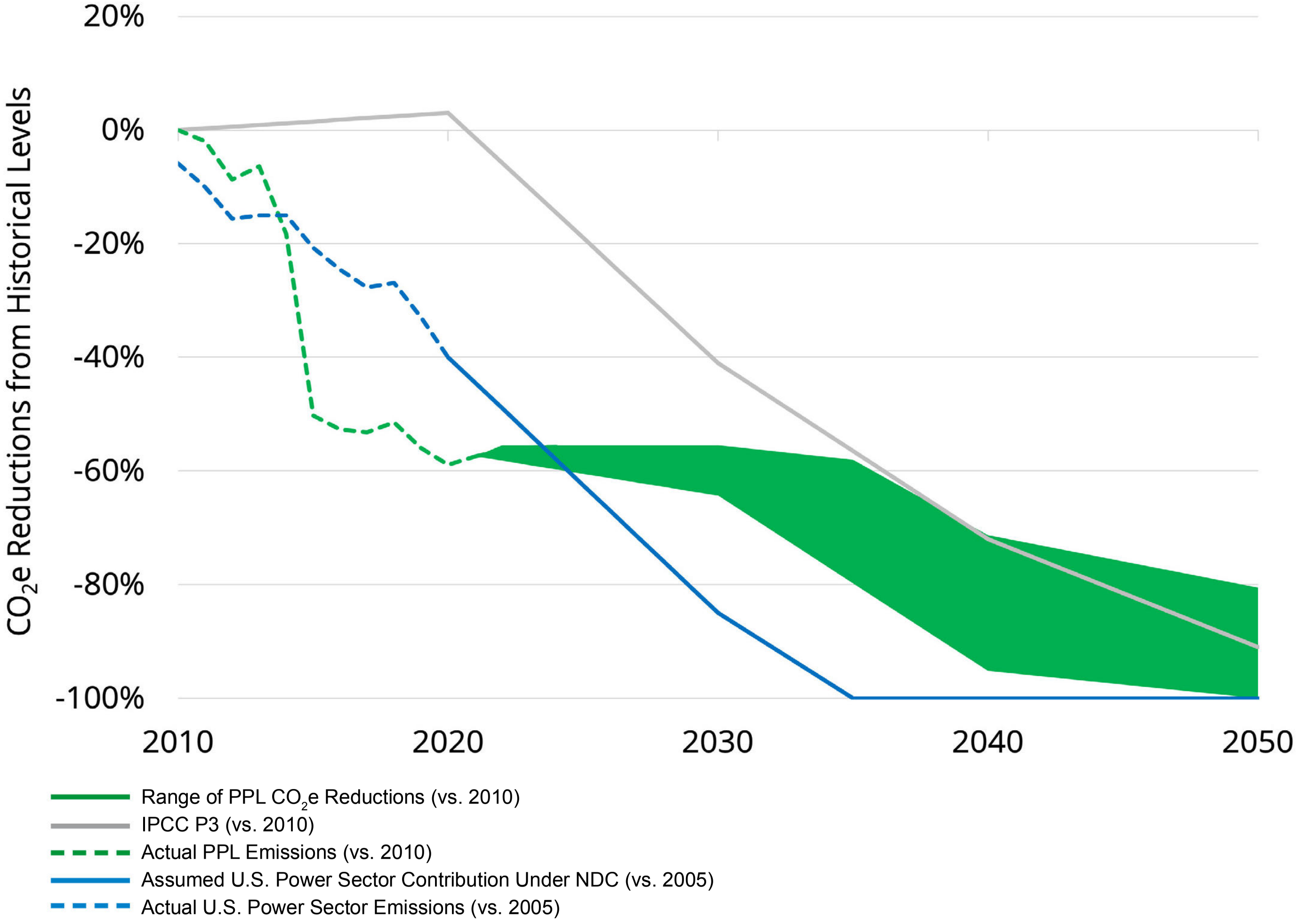


Figure 9: Energy Mix

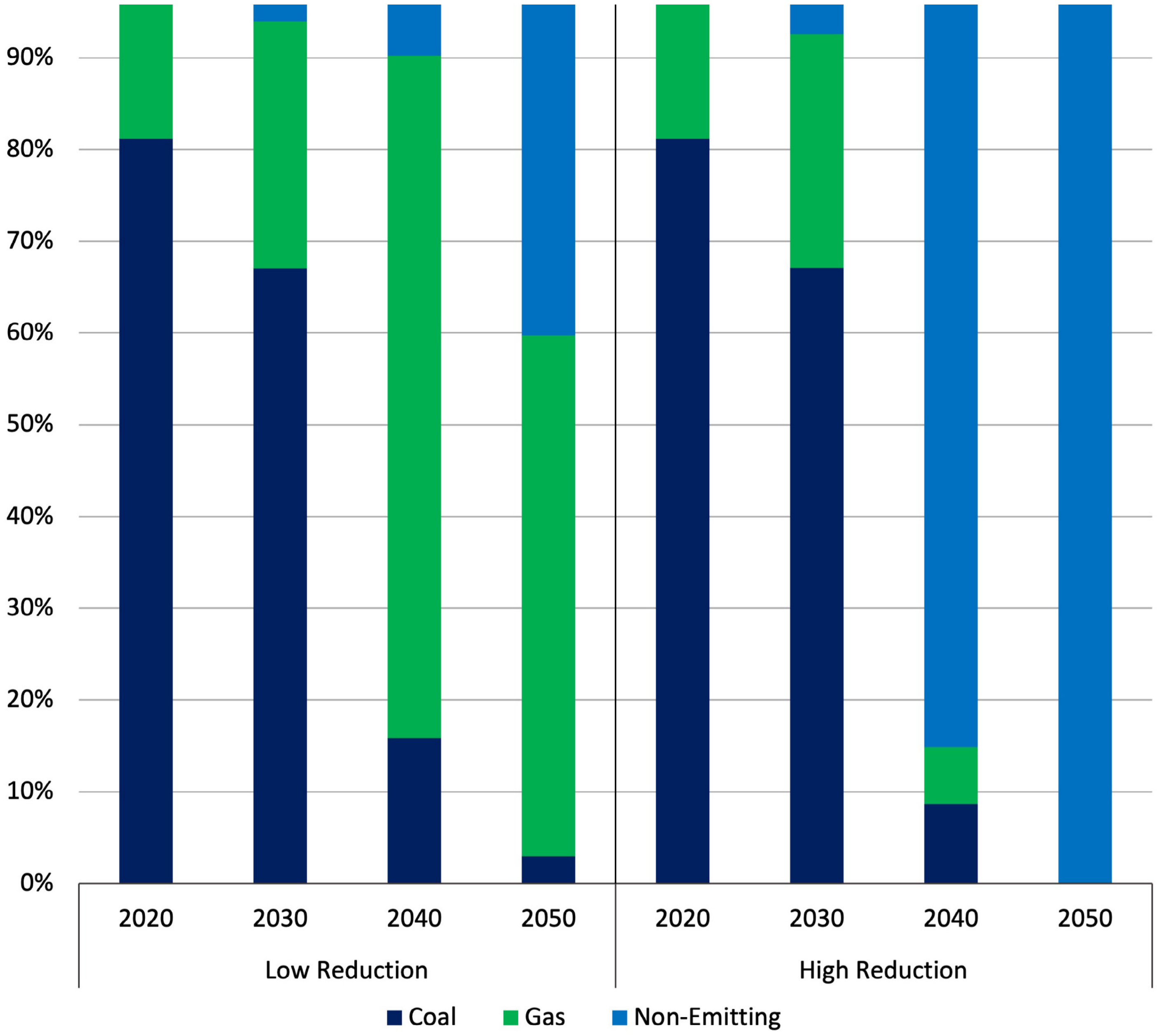


Figure 10: CO_2e Emissions (Metric Tons)

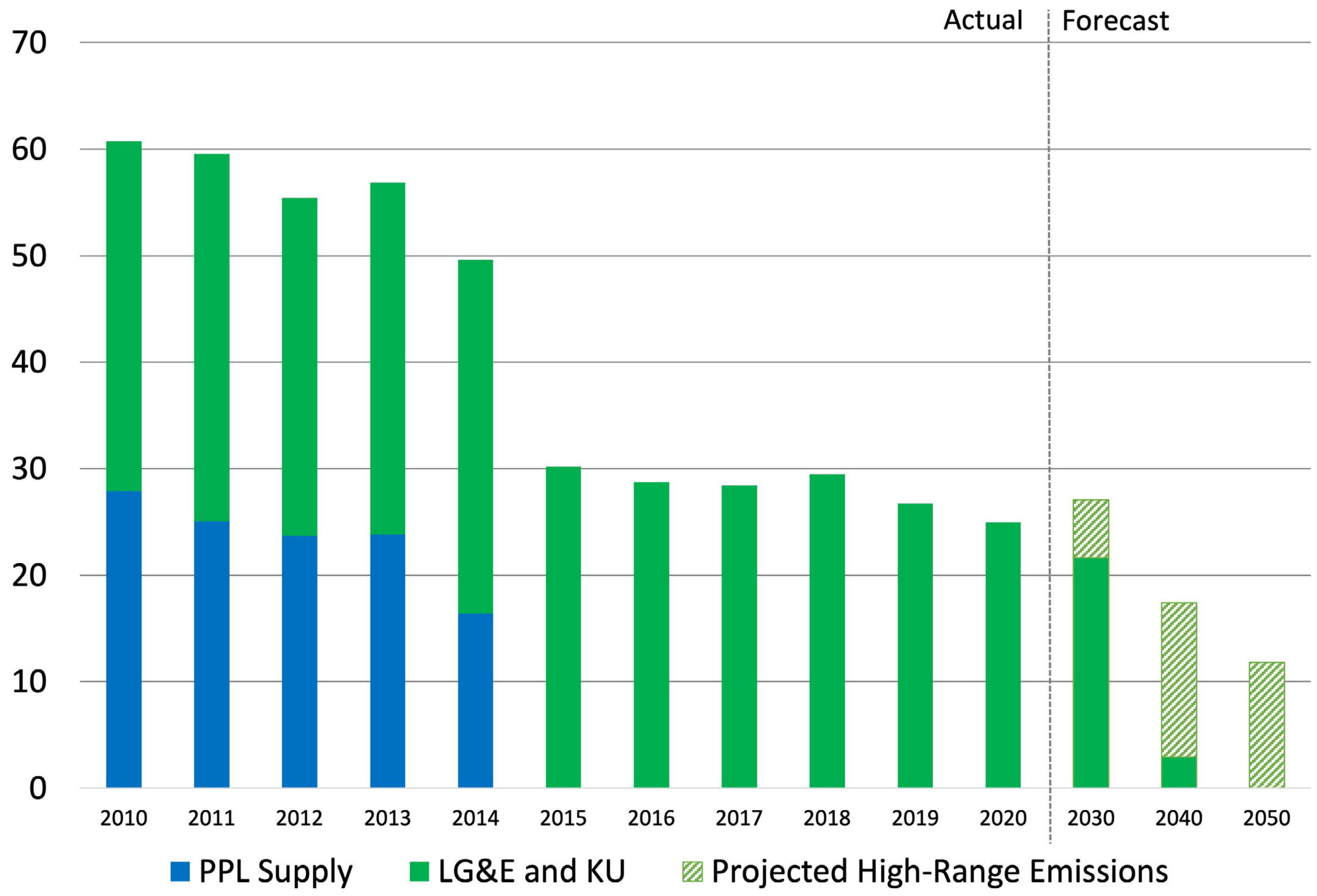


Figure 11: PPL's Kentucky Baseload Generation Resources

Power Plant	Unit	COD	Owned Capacity MW	Curently Project End of Economic Useful Life (1)
Coal				
Mill Creek	1	1972	300	2024
E.W. Brown	3	1971	412	2028
Mill Creek	2	1974	297	2028
Ghent	1	1974	475	2034
Ghent	2	1977	485	2034
Ghent	3	1981	481	2037
Ghent	4	1984	478	2037
Mill Creek	3	1978	391	2039
Mill Creek	4	1982	477	2039
Trimble County	1	1990	370	2045
Trimble County	2	2011	549	2066
Natural Gas				
Cane Run (CCGT)	7	2015	662	2055
Total Baseload			5377	

(1) Per most recent deprection study filed in Case Nos. 2020-00349 and 2020-00350

Figure 12: Reimagining Energy Delivery

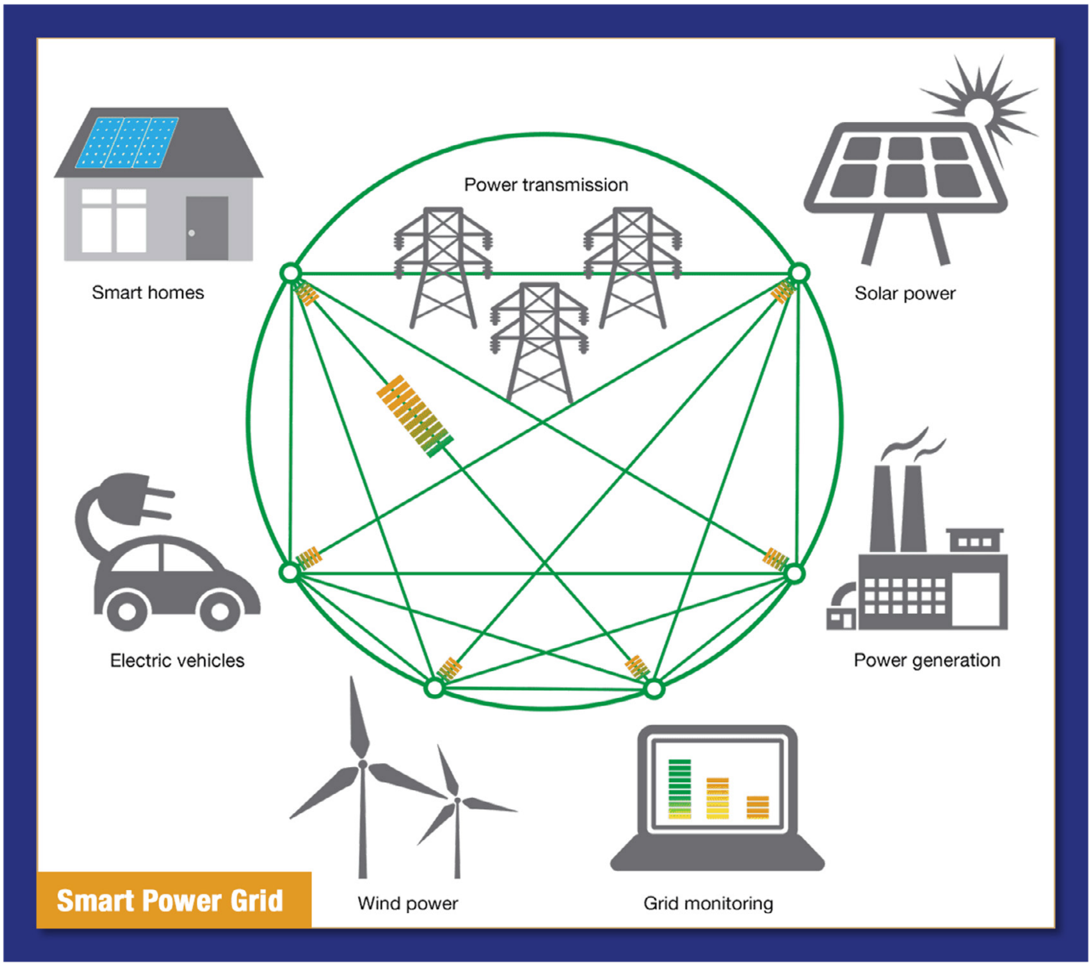


Figure 13: Projected PPL carbon emissions

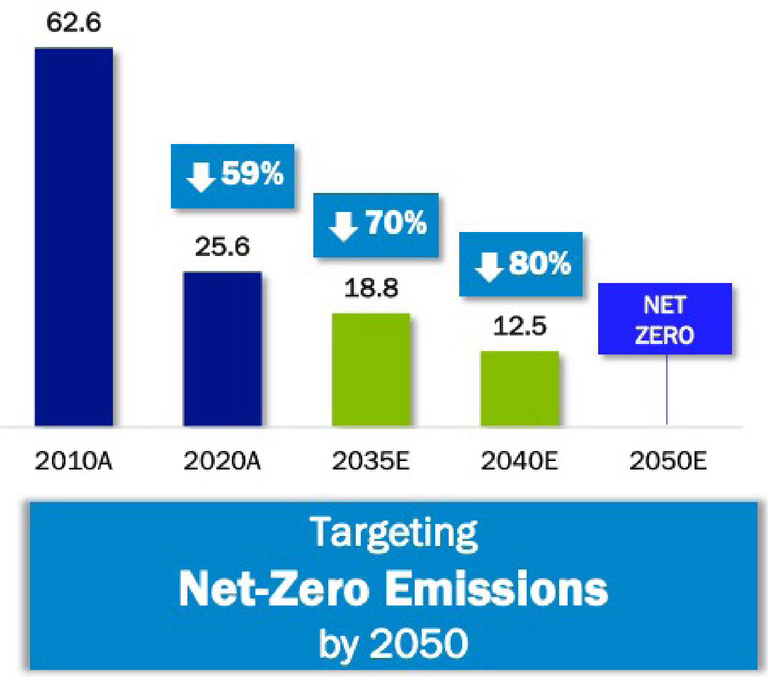
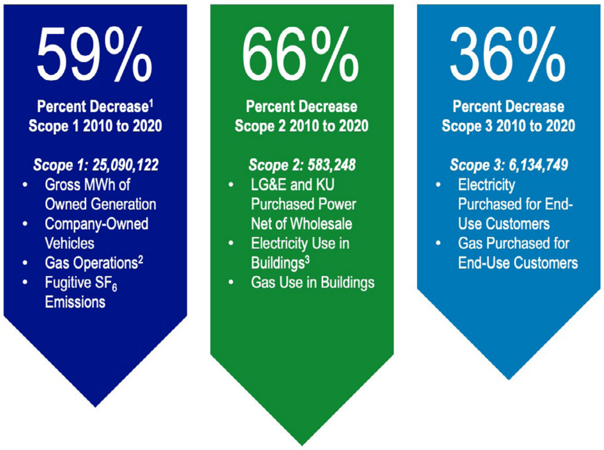


Figure 14: 2020 CO_2e emissions (metric tons)


59%

Percent Decrease[1]
Scope 1 2010 to 2020

Scope 1: 25,090,122

- Gross MWh of Owned Generation
- Company-Owned Vehicles
- Gas Operations[2]
- Fugitive SF_6 Emissions

66%

Percent Decrease
Scope 2 2010 to 2020

Scope 2: 583,248

- LG&E and KU Purchased Power Net of Wholesale
- Electricity Use in Buildings[3]
- Gas Use in Buildings

36%

Percent Decrease
Scope 3 2010 to 2020

Scope 3: 6,134,749

- Electricity Purchased for End-Use Customers
- Gas Purchased for End-Use Customers

[1] 2010 Scope 1 plant emissions is the only data point that includes PPL Energy Supply, LLC.
[2] Gas Operations are not included in the net-zero emissions goal. 2010 baseline data is estimated.
[3] LG&E and KU emissions captured in Scope 1 Gross MWh.

FORWARD-LOOKING STATEMENTS IN THIS CLIMATE ASSESSMENT REPORT

This Climate Assessment Report ("Report") contains forward-looking statements regarding, among other things, the clean energy transition, our clean energy targets and achievement of climate commitments by certain dates, strategies or goals related to environmental, social, safety and governance performance, future energy demand, the availability and cost of natural gas, carbon reduction, third-party decarbonization, the growth of solar and other renewable forms of electricity generation and storage, potential rates of reduction in coal-fired electricity generation in Kentucky, low carbon technologies, enhancement of the grid, the expected operating life of existing coal-fired electricity generation plants and PPL Corporation's corporate strategy. These statements, and all others that reflect beliefs, plans, estimates, projections, goals, targets, expectations, strategy or any other forward-looking information, are "forward-looking statements" within the meaning of the federal securities laws. PPL Corporation believes that the forward-looking statements in this Report reflect reasonable expectations and assumptions. However, it is important to understand that forward-looking statements, and their underlying assumptions, are subject to a wide range of risks and uncertainties, both known and unknown.
Any number of factors could cause actual results to be materially different from those discussed in the statements, including: market demand for energy in our service territories; weather or other conditions affecting customer energy usage and operating costs; the effect of any business or industry restructuring; the profitability and liquidity of PPL Corporation and its subsidiaries; operating performance of its facilities; environmental, legal and regulatory requirements and the related costs of compliance; development of new projects, markets and technologies for the generation and delivery of electricity; performance of new ventures; asset or business acquisitions and dispositions; receipt of necessary government permits, approvals, rate relief and regulatory cost recovery; capital market conditions and decisions regarding capital structure; the outcome of litigation against PPL Corporation and its subsidiaries; the securities and credit ratings of PPL Corporation and its subsidiaries; political, regulatory or economic conditions in states, regions or countries where PPL Corporation or its subsidiaries conduct business; new state, federal or foreign legislation; commitments and liabilities of PPL Corporation and its subsidiaries; and catastrophic events such as fires, earthquakes, explosions, floods, hurricanes and other storms, droughts or other similar occurrences as well as cyber intrusion or other terrorist incidents and their direct or indirect effect on PPL Corporation's businesses and the U.S. or U.K. electricity grids. All forward-looking statements in this Report should be considered in light of these important factors. Further information on these and other risks and uncertainties is available in PPL Corporation's Form 10-K and other reports on file with the Securities and Exchange Commission.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILTIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.12

Responding Witness: Stuart A. Wilson

Q-1.12. Refer to the 2021 IRP, Volume I, page 5-31, stating that overnight charging of EVs likely could be accomplished using the Companies' existing dispatchable generation assets, whereas charging of EVs in the early evening "could exacerbate summer and winter peak energy requirements and potentially create the need for additional peaking capacity or load control programs ……..''Please provide any analyses, workpapers, and documentation (in machine readable and unprotected format, with formulas intact) supporting the above quoted statement.

a. Have the Companies prepared or caused to be prepared any analysis of (i) the potential for measures to shift EV charging to off- peak hours and (ii) the potential for incentivizing customers to shift EV charging to off-peak hours via changes in the Companies' rate design? If so, please produce any such analyses. If not, please explain in detail why not.

b. Did the companies model how expanded distributed generation (for example that might occur with the elimination of the 1% cap on net metered solar), and expanded utility scale solar combinedwith battery storage, could be used to moderate the effects of expanded EV adoption on load profiles? If so, please produce any such analyses. If not, please explain in detail why not.

A-1.12. See IRP, Volume I, page 5-32, Figures 5-17 and 5-18 and the EV and Energy Requirements forecast folders included in the attachment in response to Question No. 3 at the following paths: *Electric_Load_Forecast\2_Forecasts\EV* and *Electric_Load_Forecast\4_Demand_Forecasts\1_Hourly_Demand\Load_Duration_Curve\Data*. Also, see attachment in response to SREA 1-11b. The peak of the natural charging profile for EVs partly or fully coincides with the summer and winter peak hours, particularly for hours 18 to 22 (5:00 p.m. to 10:00 p.m.) in the winter. Therefore, natural EV charging would likely add to winter and summer peak demands. However, managed or "overnight" EV charging would shift most of the charging load into the late evening or early morning hours, out of the summer and winter peak hours.

a. No. The Companies have not performed such analyses. See the responses to PSC 1-18a and PSC 1-25b.

b. No. The Companies have not performed this analysis. Distributed solar generation would not be available in the overnight hours when electric vehicles are most likely to charge. See the response to SREA 1-7.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.13

Responding Witness: Stuart A. Wilson

Q-1.13. Have the Companies prepared or caused to be prepared any estimate of current or projected switching from gas to electric appliances by LG&E/KU's customers, and/or of the effects on load of such switching? If so, please produce any such estimates and supporting analyses, workpapers, and documentation (in machine-readable format with formulas intact). If not, please explain in detail why not.

A-1.13. See Volume I, page 5-33, Tables 5-11 and 5-12. Support for these tables can be found in the attachments to the response to Question No. 3, specifically in the following file path:
Electric_Load_Forecast\6_IRP\Vol_I_Data\Space_Heating_Electrification.

Electric end-uses are modeled in the base load forecast using a statistically-adjusted end-use model (see the response to PSC 1-40b and Volume II, Electric Sales and Demand Forecast Process, Section 4.1.2). The high load forecast reflects an electrification scenario where gas furnaces are replaced with electric space heating over time (see discussion beginning on page 5-34 in Volume I and the response to PSC 1-19b). Figure 5-20 on page 5-36 shows the impact of space heating electrification in the high forecast on energy requirements versus the base case forecast. Figures 5-21 and 5-22 show the impact of space heating electrification on summer and winter peak demand, respectively. Support for the high load forecast is included in the attachments to the response to Question No. 3, specifically in the following file path:
Electric_Load_Forecast \6_IRP\Vol_I_Data\Scenarios\High_Scenario_Files

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.14

Responding Witness: John Bevington / Eileen L. Saunders

Q-1.14. Refer to the 2021 IRP, Volume I, Tables 8-12 and 8-13.

a. Please explain in detail why the incremental and cumulative energy and demand impacts of the AMS Customer Service Offering is 0.0 for all years.

b. Please explain in detail why incremental DSM energy and demand impacts are zero for all DSM programs from 2026 through 2036. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

c. With respect to the DSM Summer Peak Demand Reductions shown in Table8-12, please clarify if the negative values for "Residential and Small Nonresidential Demand Conservation" are intended to reflect an increase in demand. If so, please explain in full how this demand conservation program increases the summer peak demand.

d. With respect to the DSM Summer Peak Demand Reductions shown in Table 8-12, please clarify whether the negative values for "Total Annual Demand Reduction" are intended to reflect a net increase in demand. If so, please explain in full how DSM increases the summer peak demand.

A-1.14.

a. The AMS Customer Service Offering assumed no energy or demand savings when it was proposed to the PSC. See Case No. 2014-00003, Exhibit MEH-1, Section 7.1. That is why the Companies' IRP does not assume any energy and demand savings for the program.

b. The current DSM Portfolio is currently only approved through the end of 2025, which is why there are no projections for incremental energy and demand impacts beyond this date.

c. The negative values reflect expected device removals in the program because of reduced incentives offered in the program as well as limited customer communications promoting enrollments to the program. See Case No. 2017-00441, Exhibit GSL-1, Section 3.1, for more detailed information.[3]

d. See the response to part (c).

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[3] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.15

Responding Witness: Stuart A. Wilson

Q-1.15. Refer to Volume I at page 5-19, which states: "Furthermore, because annual peak demands can occur during the winter months and because winter peaks typically occur during nighttime hours, solar generation has virtually no value in the Companies service territories as a source of winter capacity." Please explain why the Company's winter peak occurs at night and detail the steps, if any, the Company has taken to shift and to flatten this peak.

a. Refer to Volume I, Tables 5-15 and 5-16. Have the Companies considered solar paired with storage, which would allow the storage to benefit from the federal investment tax credit? Please provide any supporting workpapers (in machine readable and unprotected format, with formulas intact). If not, why not?

A-1.15. Winter peaks occur during nighttime hours either early in the morning when residents are waking up, turning on lights, showering, and heating their homes or in the evening when residents are returning from work, turning on lights, cooking, and heating their homes. Peaks in the winter or summer tend to occur during periods of the most extreme temperatures, and extreme temperatures in the winter most often occur early in the morning or late in the evening. When paired with other behavioral tendencies, this leads to a greater possibility of morning and evening peaks. To shift or flatten winter peaks, the Companies have offered RTOD rates that are utilized by a small number of customers. The winter and summer peak time periods correspond with the time of the day in which the system is most likely to peak.

a. See the response to SREA 1-7.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.16

Responding Witness: Stuart A. Wilson

Q-1.16. Refer Section 4.8 ("Weather-Year Forecasts") of the Electric Sales & Demand Forecast Process (July 2021).

a. Please explain in full why the Companies rely on 48 years of actualweather (1973 through 2020) as compared with a shorter period (e.g., 30 years or 20 years).

b. Are the Companies aware of any empirical analyses or studies validating a hypothesis that energy forecasts using the most recent40+ years of weather data would have greater predictive value than an energy forecast using the most recent 30 or 20 years of weather data? If so, please produce such analyses or studies.

A-1.16.

a. Weather in the base, high, and low load forecasts is assumed to be "normal" throughout the 15-year forecast period, and normal weather is computed using the most recent 20 years of historical weather. See the response to PSC 1-37 as well as Section 3.1 of the referenced document.

For the Companies' Reserve Margin Analysis, 48 "weather year" forecasts were developed for a single year (2025) to evaluate the uncertainty in the base load forecast due to weather. Each weather year forecast is a forecast of base case hourly load with a different weather assumption; all other forecast assumptions are unchanged. For example, the 1994 weather year forecast is a forecast of base case hourly load in 2025 developed with the assumption that weather in 2025 will be the same as it was in 1994 (and not normal). The training period for the models used to produce the weather-year forecasts is not 48 years.

b. See the response to part (a).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.17

Responding Witness: Stuart A. Wilson

Q-1.17. For the Companies' coal-fired units, please provide the following historical annual data by unit, or, if the Companies do not maintain unit- level data, by plant, from 2012 to present:

a. Fixed O&M cost

b. Variable O&M cost (without fuel)

c. Fuel costs

d. Capital costs

e. Heat rate

f. Generation

g. Capacity rating

h. Capacity factor

i. Forced outage rate

j. Planned outage rate

k. Energy revenues

l. Capacity revenues

m. Ancillary services revenues

A-1.17.

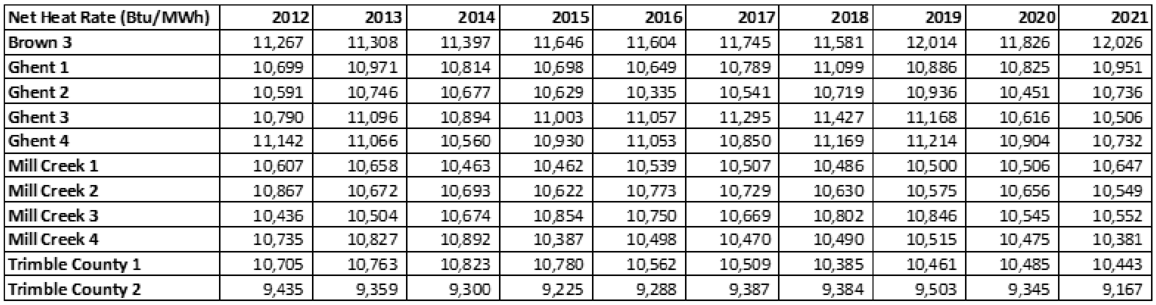
a. See attached.

b. See attached.

c. See attached.

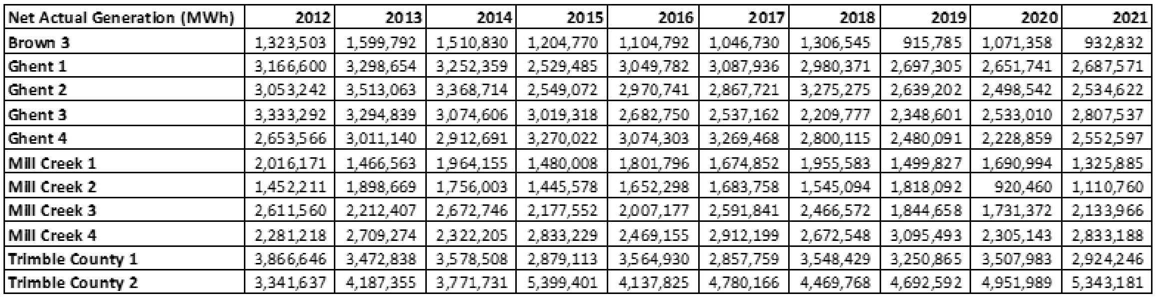
d. See attached.

e.



Net Heat Rate (Btu/MWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	11,267	11,308	11,397	11,646	11,604	11,745	11,581	12,014	11,826	12,026
Ghent 1	10,699	10,971	10,814	10,698	10,649	10,789	11,099	10,886	10,825	10,951
Ghent 2	10,591	10,746	10,677	10,629	10,335	10,541	10,719	10,936	10,451	10,736
Ghent 3	10,790	11,096	10,894	11,003	11,057	11,295	11,427	11,168	10,616	10,506
Ghent 4	11,142	11,066	10,560	10,930	11,053	10,850	11,169	11,214	10,904	10,732
Mill Creek 1	10,607	10,658	10,463	10,462	10,539	10,507	10,486	10,500	10,506	10,647
Mill Creek 2	10,867	10,672	10,693	10,622	10,773	10,729	10,630	10,575	10,656	10,549
Mill Creek 3	10,436	10,504	10,674	10,854	10,750	10,669	10,802	10,846	10,545	10,552
Mill Creek 4	10,735	10,827	10,892	10,387	10,498	10,470	10,490	10,515	10,475	10,381
Trimble County 1	10,705	10,763	10,823	10,780	10,562	10,509	10,385	10,461	10,485	10,443
Trimble County 2	9,435	9,359	9,300	9,225	9,288	9,387	9,384	9,503	9,345	9,167

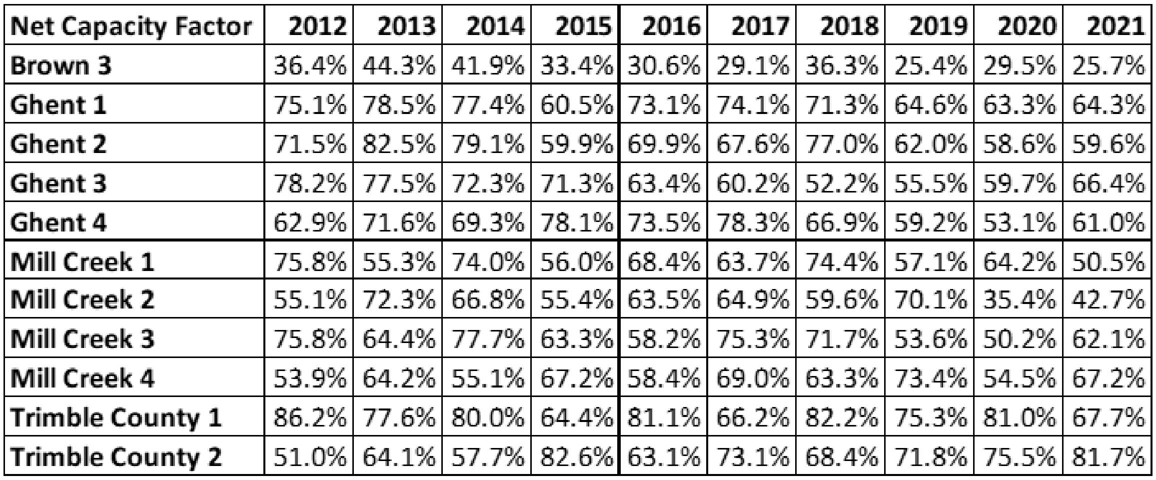
f.



Net Actual Generation (MWh)	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	1,323,503	1,599,792	1,510,830	1,204,770	1,104,792	1,046,730	1,306,545	915,785	1,071,358	932,832
Ghent 1	3,166,600	3,298,654	3,252,359	2,529,485	3,049,782	3,087,936	2,980,371	2,697,305	2,651,741	2,687,571
Ghent 2	3,053,242	3,513,063	3,368,714	2,549,072	2,970,741	2,867,721	3,275,275	2,639,202	2,498,542	2,534,622
Ghent 3	3,333,292	3,294,839	3,074,606	3,019,318	2,682,750	2,537,162	2,209,777	2,348,601	2,533,010	2,807,537
Ghent 4	2,653,566	3,011,140	2,912,691	3,270,022	3,074,303	3,269,468	2,800,115	2,480,091	2,228,859	2,552,597
Mill Creek 1	2,016,171	1,466,563	1,964,155	1,480,008	1,801,796	1,674,852	1,955,583	1,499,827	1,690,994	1,325,885
Mill Creek 2	1,452,211	1,898,669	1,756,003	1,445,578	1,652,298	1,683,758	1,545,094	1,818,092	920,460	1,110,760
Mill Creek 3	2,611,560	2,212,407	2,672,746	2,177,552	2,007,177	2,591,841	2,466,572	1,844,658	1,731,372	2,133,966
Mill Creek 4	2,281,218	2,709,274	2,322,205	2,833,229	2,469,155	2,912,199	2,672,548	3,095,493	2,305,143	2,833,188
Trimble County 1	3,866,646	3,472,838	3,578,508	2,879,113	3,564,930	2,857,759	3,548,429	3,250,865	3,507,983	2,924,246
Trimble County 2	3,341,637	4,187,355	3,771,731	5,399,401	4,137,825	4,780,166	4,469,768	4,692,592	4,951,989	5,343,181

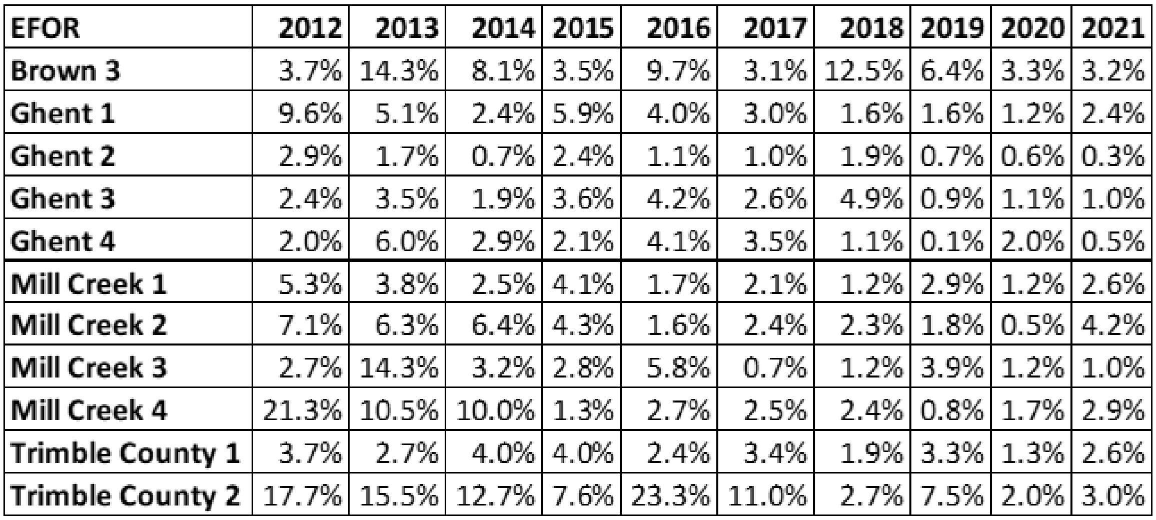
g. Unit capacity ratings are provided in Volume I, Table 8-3.

h.



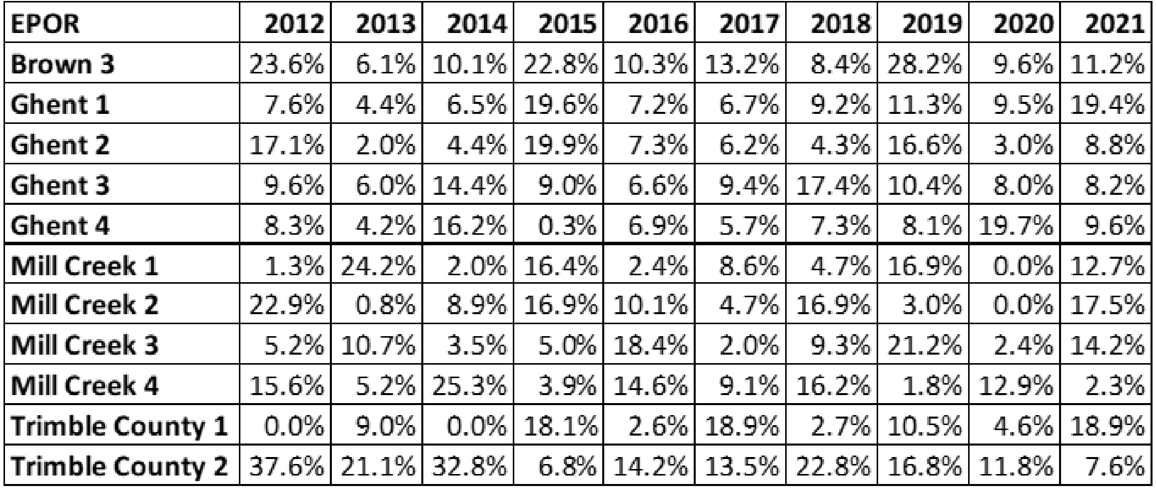
Net Capacity Factor	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	36.4%	44.3%	41.9%	33.4%	30.6%	29.1%	36.3%	25.4%	29.5%	25.7%
Ghent 1	75.1%	78.5%	77.4%	60.5%	73.1%	74.1%	71.3%	64.6%	63.3%	64.3%
Ghent 2	71.5%	82.5%	79.1%	59.9%	69.9%	67.6%	77.0%	62.0%	58.6%	59.6%
Ghent 3	78.2%	77.5%	72.3%	71.3%	63.4%	60.2%	52.2%	55.5%	59.7%	66.4%
Ghent 4	62.9%	71.6%	69.3%	78.1%	73.5%	78.3%	66.9%	59.2%	53.1%	61.0%
Mill Creek 1	75.8%	55.3%	74.0%	56.0%	68.4%	63.7%	74.4%	57.1%	64.2%	50.5%
Mill Creek 2	55.1%	72.3%	66.8%	55.4%	63.5%	64.9%	59.6%	70.1%	35.4%	42.7%
Mill Creek 3	75.8%	64.4%	77.7%	63.3%	58.2%	75.3%	71.7%	53.6%	50.2%	62.1%
Mill Creek 4	53.9%	64.2%	55.1%	67.2%	58.4%	69.0%	63.3%	73.4%	54.5%	67.2%
Trimble County 1	86.2%	77.6%	80.0%	64.4%	81.1%	66.2%	82.2%	75.3%	81.0%	67.7%
Trimble County 2	51.0%	64.1%	57.7%	82.6%	63.1%	73.1%	68.4%	71.8%	75.5%	81.7%

i.



EFOR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	3.7%	14.3%	8.1%	3.5%	9.7%	3.1%	12.5%	6.4%	3.3%	3.2%
Ghent 1	9.6%	5.1%	2.4%	5.9%	4.0%	3.0%	1.6%	1.6%	1.2%	2.4%
Ghent 2	2.9%	1.7%	0.7%	2.4%	1.1%	1.0%	1.9%	0.7%	0.6%	0.3%
Ghent 3	2.4%	3.5%	1.9%	3.6%	4.2%	2.6%	4.9%	0.9%	1.1%	1.0%
Ghent 4	2.0%	6.0%	2.9%	2.1%	4.1%	3.5%	1.1%	0.1%	2.0%	0.5%
Mill Creek 1	5.3%	3.8%	2.5%	4.1%	1.7%	2.1%	1.2%	2.9%	1.2%	2.6%
Mill Creek 2	7.1%	6.3%	6.4%	4.3%	1.6%	2.4%	2.3%	1.8%	0.5%	4.2%
Mill Creek 3	2.7%	14.3%	3.2%	2.8%	5.8%	0.7%	1.2%	3.9%	1.2%	1.0%
Mill Creek 4	21.3%	10.5%	10.0%	1.3%	2.7%	2.5%	2.4%	0.8%	1.7%	2.9%
Trimble County 1	3.7%	2.7%	4.0%	4.0%	2.4%	3.4%	1.9%	3.3%	1.3%	2.6%
Trimble County 2	17.7%	15.5%	12.7%	7.6%	23.3%	11.0%	2.7%	7.5%	2.0%	3.0%

j.



EPOR	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	23.6%	6.1%	10.1%	22.8%	10.3%	13.2%	8.4%	28.2%	9.6%	11.2%
Ghent 1	7.6%	4.4%	6.5%	19.6%	7.2%	6.7%	9.2%	11.3%	9.5%	19.4%
Ghent 2	17.1%	2.0%	4.4%	19.9%	7.3%	6.2%	4.3%	16.6%	3.0%	8.8%
Ghent 3	9.6%	6.0%	14.4%	9.0%	6.6%	9.4%	17.4%	10.4%	8.0%	8.2%
Ghent 4	8.3%	4.2%	16.2%	0.3%	6.9%	5.7%	7.3%	8.1%	19.7%	9.6%
Mill Creek 1	1.3%	24.2%	2.0%	16.4%	2.4%	8.6%	4.7%	16.9%	0.0%	12.7%
Mill Creek 2	22.9%	0.8%	8.9%	16.9%	10.1%	4.7%	16.9%	3.0%	0.0%	17.5%
Mill Creek 3	5.2%	10.7%	3.5%	5.0%	18.4%	2.0%	9.3%	21.2%	2.4%	14.2%
Mill Creek 4	15.6%	5.2%	25.3%	3.9%	14.6%	9.1%	16.2%	1.8%	12.9%	2.3%
Trimble County 1	0.0%	9.0%	0.0%	18.1%	2.6%	18.9%	2.7%	10.5%	4.6%	18.9%
Trimble County 2	37.6%	21.1%	32.8%	6.8%	14.2%	13.5%	22.8%	16.8%	11.8%	7.6%

k. The Companies do not have this data.

l. The Companies do not have this data.

m. The Companies do not have this data.

	Fixed Costs by Unit									
	Year									
Unit	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Brown 3	20,203,564.17	14,162,657.31	16,595,605.36	16,652,320.68	17,868,614.91	17,262,471.42	17,744,784.88	23,232,462.01	29,786,862.81	29,204,470.27
Ghent Common*	-	-	-	0.00	0.00	-	-	(1,809,534.72)	(3,183,251.16)	(1,549,333.52)
Ghent 1	16,899,354.57	15,025,924.53	16,751,941.19	25,766,169.85	18,220,607.96	18,693,378.90	20,806,040.23	20,801,878.29	12,095,385.13	19,076,693.80
Ghent 2	20,052,227.94	10,932,467.81	13,878,745.09	17,421,724.87	16,986,275.12	16,273,757.26	19,832,413.50	21,645,144.19	19,861,237.69	23,339,183.36
Ghent 3	14,006,950.09	10,802,223.14	16,061,116.91	17,375,590.00	18,633,067.31	18,087,487.04	20,928,250.00	18,648,536.03	15,808,512.77	18,723,315.60
Ghent 4	15,561,188.04	17,555,994.89	25,901,395.91	18,480,076.64	18,277,729.84	19,744,579.13	18,438,373.00	18,452,242.13	24,087,424.78	21,062,435.28
Mill Creek Common*	(0.00)	0.00	0.00	0.00	(0.00)	-	0.00	(666,646.46)	(1,147,397.69)	(813,333.55)
Mill Creek 1	11,388,530.35	18,286,796.87	11,630,795.90	15,029,838.57	12,736,475.51	15,931,094.97	14,317,939.01	15,785,543.16	14,112,368.75	15,193,668.64
Mill Creek 2	16,964,126.55	10,344,029.49	13,918,985.08	12,825,791.25	13,894,312.49	10,981,938.73	13,079,893.27	13,643,343.41	12,216,719.63	12,729,836.48
Mill Creek 3	10,683,123.37	16,116,323.69	11,740,812.01	14,826,858.97	18,786,038.32	15,951,025.32	17,130,339.17	17,023,310.40	14,812,184.19	20,188,749.21
Mill Creek 4	16,369,557.93	14,832,203.51	22,483,349.12	17,427,633.24	20,598,636.38	18,888,031.29	18,852,078.50	18,374,959.55	19,620,419.55	18,000,591.62
Trimble County 1**	10,982,531.53	13,506,324.96	12,011,125.10	16,620,462.09	13,634,742.76	14,219,341.89	15,796,272.90	16,245,929.80	17,395,593.42	19,453,730.98
Trimble County 2**	15,408,566.24	14,631,396.29	18,851,204.38	17,053,618.60	20,172,254.81	19,371,321.40	21,042,494.51	21,101,574.64	22,930,741.94	21,995,133.00
	168,519,720.78	156,196,342.49	179,825,076.05	189,480,084.76	189,808,755.41	185,404,427.35	197,968,878.97	202,478,742.43	198,396,801.81	216,605,141.17

***** Refined coal proceeds
****** Annual amounts represent 75% ownership

	Variable Costs by Unit									
	Year									
Unit	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Brown 3	767,726.73	2,124,278.41	2,033,729.40	1,786,261.13	2,959,297.76	1,570,176.25	1,794,811.14	1,309,062.62	1,545,372.29	1,567,759.27
Ghent 1	4,882,918.18	5,055,674.24	4,251,336.01	4,362,032.63	5,284,184.34	5,174,645.03	4,242,234.04	3,178,638.46	3,320,162.43	3,483,444.02
Ghent 2	2,028,082.30	2,543,404.53	2,439,231.78	1,893,040.45	3,982,693.54	3,550,752.32	2,932,180.08	2,458,132.62	2,351,436.48	2,209,128.23
Ghent 3	6,277,538.24	5,796,820.29	4,471,061.78	4,684,733.81	5,460,021.96	4,832,901.11	3,457,948.79	3,361,348.47	3,906,206.13	4,595,848.24
Ghent 4	5,400,731.47	6,128,957.06	6,420,755.99	8,184,584.74	6,299,562.55	6,433,679.62	4,372,922.87	4,061,876.32	3,663,846.37	3,958,421.52
Mill Creek 1	1,215,582.08	971,905.33	1,120,367.46	1,164,814.81	2,541,974.90	2,183,280.86	1,915,135.78	1,640,980.62	1,769,420.90	1,317,168.00
Mill Creek 2	978,591.86	1,148,439.50	1,037,354.66	1,145,561.43	2,459,561.14	2,578,897.81	1,683,256.74	1,934,185.97	1,044,409.87	1,081,932.46
Mill Creek 3	2,717,857.88	2,239,513.55	2,378,831.85	2,560,873.50	2,573,723.93	3,366,147.47	3,317,413.93	2,437,451.95	2,195,554.15	3,115,836.47
Mill Creek 4	2,530,241.07	2,542,549.32	2,048,444.48	3,282,660.02	3,872,967.18	3,334,151.58	3,053,019.59	4,049,259.51	3,093,680.13	3,919,870.78
Trimble County 1*	3,180,949.91	2,920,095.89	3,355,862.56	2,573,674.88	2,967,685.75	2,416,243.11	2,652,782.83	2,283,658.73	2,551,453.58	1,938,960.94
Trimble County 2*	3,474,502.78	3,916,171.55	3,441,000.48	5,485,551.69	4,096,138.58	4,471,263.95	4,325,290.06	3,938,662.18	4,268,889.78	4,383,917.94
	33,454,722.50	35,387,809.67	32,997,976.45	37,123,789.09	42,497,811.63	39,912,139.11	33,746,995.85	30,653,257.45	29,710,432.11	31,572,287.87

***** Annual amounts represent 75% ownership

	Fuel Costs by Unit									
	Year									
Unit	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
Brown 3	46,141,000.97	55,014,482.97	54,092,936.95	41,200,015.06	34,911,627.46	33,236,800.58	40,548,075.19	25,984,556.64	33,057,344.28	29,308,453.31
Ghent 1	76,969,051.60	78,426,824.53	79,148,499.20	58,834,052.23	66,463,223.75	67,002,486.65	62,621,485.25	55,145,369.69	55,609,419.70	57,119,328.08
Ghent 2	73,080,026.64	81,944,619.87	81,261,912.93	60,444,107.28	63,042,435.73	60,428,465.86	66,588,037.05	56,103,948.73	50,483,218.89	52,429,834.87
Ghent 3	81,572,429.11	80,438,605.94	75,498,423.84	73,671,929.80	61,119,662.82	57,523,593.75	49,262,545.36	50,727,967.60	52,012,152.14	57,069,765.90
Ghent 4	67,778,359.24	73,341,480.99	72,630,502.97	78,598,159.94	68,269,237.97	70,928,648.81	59,601,353.87	52,626,775.82	47,219,947.38	53,192,562.26
Mill Creek 1	49,641,182.98	37,127,997.53	49,301,196.36	35,886,165.38	41,653,582.13	35,559,008.78	40,883,397.59	32,475,578.01	37,068,210.64	29,231,699.13
Mill Creek 2	36,743,843.21	48,335,532.69	44,759,499.40	35,511,757.17	39,095,866.97	36,503,783.13	32,770,221.15	39,427,299.93	20,588,114.87	24,201,229.59
Mill Creek 3	63,997,360.23	56,532,661.10	68,848,915.19	55,673,565.75	48,236,470.44	56,822,722.09	53,867,568.61	42,021,209.88	38,433,607.18	46,025,601.00
Mill Creek 4	57,890,135.04	71,081,342.27	61,487,445.40	69,222,431.01	58,143,280.77	62,908,630.65	57,360,555.81	67,762,368.00	51,358,298.29	59,636,019.61
Trimble County 1*	70,487,764.19	65,295,183.99	66,134,637.50	52,100,602.20	59,291,621.58	44,659,722.74	53,387,747.25	49,714,276.29	53,781,092.79	43,436,242.59
Trimble County 2*	59,308,189.16	72,958,642.06	62,887,515.38	86,824,438.88	63,748,842.13	72,229,392.42	64,631,043.44	69,097,083.24	71,503,687.81	73,598,454.12
	683,609,342.37	720,497,373.94	716,051,485.12	647,967,224.70	603,975,851.75	597,803,255.46	581,522,030.57	541,086,433.83	511,115,093.97	525,249,190.46

***** Annual amounts represent 75% ownership

	Capital Costs by Unit									
	Year									
Unit	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
KU Common Generation	199,340.26	593,754.54	(511,189.44)	430,986.12	447,521.03	496,800.91	86,735.71	217,504.86	227,845.27	(15,629.71)
Brown Common	6,505,352.61	5,317,423.46	1,510,366.50	2,682,876.74	1,728,717.59	1,662,786.48	8,363,916.22	16,610,375.00	3,925,116.05	1,303,289.42
Brown 3	54,994,799.44	29,745,834.47	70,896,556.72	88,431,108.76	16,055,936.28	5,393,393.97	17,445,984.71	42,545,025.30	25,030,876.97	24,516,715.79
Ghent Common	131,380,206.78	96,683,557.25	27,944,195.31	21,520,299.88	19,075,014.47	20,351,369.87	27,208,770.33	23,680,344.85	8,793,488.74	12,739,787.11
Ghent 1	13,309,739.32	50,299,996.65	77,725,906.75	40,995,982.12	7,240,179.84	12,344,230.15	7,309,708.46	9,934,941.72	18,553,372.70	31,373,140.41
Ghent 2	27,451,456.56	22,774,968.48	49,568,662.31	57,819,916.82	13,096,703.84	6,984,000.45	4,276,972.68	17,722,435.72	3,947,516.73	7,954,302.28
Ghent 3	25,383,525.12	99,845,613.11	53,404,914.80	14,771,790.42	7,409,811.24	14,587,528.04	29,600,965.22	10,357,597.00	5,984,940.30	5,684,277.92
Ghent 4	13,459,936.04	81,424,773.56	63,942,668.35	19,017,849.98	2,494,584.75	35,965,273.44	85,062,970.47	20,999,286.21	27,699,612.73	55,153,837.96
Mill Creek Common	(1,043,452.79)	362,680.93	718,236.24	131,932.16	406,605.93	65,570.75	748,924.07	2,915,384.28	3,799,381.34	9,310,881.79
Mill Creek 1	21,226,281.74	67,018,625.83	83,168,247.98	73,537,625.51	4,977,361.23	4,915,665.40	2,775,249.35	11,668,255.04	3,645,452.34	3,330,076.08
Mill Creek 2	21,446,081.32	36,708,688.89	83,213,216.35	70,997,431.88	460,510.60	2,160,496.59	11,995,946.64	4,016,721.67	3,685,286.60	8,058,629.03
Mill Creek 3	11,532,781.59	52,690,192.39	26,326,233.42	159,685,459.28	78,173,414.11	6,408,994.81	6,953,654.02	25,247,838.91	2,554,761.37	28,691,750.77
Mill Creek 4	36,786,149.37	125,501,730.18	215,785,762.69	29,218,574.36	18,871,748.28	126,703,245.32	162,108,494.10	54,313,715.71	31,546,528.59	4,816,707.78
Trimble County Common*	13,088.51	38,441.05	264,941.47	75,286.20	23,129,265.64	49,262,323.86	28,835,651.30	18,515,386.01	11,313,389.70	8,907,031.63
Trimble County 1*	5,249,740.88	15,069,847.35	44,509,768.93	46,613,254.52	9,010,140.72	18,893,980.77	4,225,686.54	14,256,180.04	4,224,029.47	17,670,881.66
Trimble County 2*	34,587,227.53	7,620,271.87	21,437,843.83	10,212,529.83	46,729,521.46	90,780,560.13	89,011,777.29	51,338,018.87	29,007,513.15	46,988,206.14
	395,777,561.41	685,785,222.01	818,907,155.15	633,029,041.72	247,130,798.39	394,816,633.55	477,560,755.18	307,511,131.33	179,786,150.73	265,196,226.35

* Annual amounts represent 75% ownership

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.18

Responding Witness: Stuart A. Wilson / Daniel K. Arbough

Q-1.18. For each existing coal-fired unit, please provide the following projected annual data by unit, or, if the Companies do not maintain unit-level data, by plant, for the economic analysis period in this filing (i.e., 2021-2036):

a. Fixed O&M cost

b. Variable O&M cost (without fuel)

c. Fuel costs

d. Capital costs

e. Capacity factor

f. Generation

g. Depreciation

h. Heat rate

i. Forced outage rate

j. Planned outage rate

k. Energy revenues

l. Capacity revenues

m. Ancillary services revenues

A-18.

a. See attached.

b. See attached.

c. Annual cost of fuel is provided in Volume I, Table 8-7.

d. See the response to Question No. 22(a).

e. Annual capacity factors are provided in Volume I, Table 8-4.

f. See attached.

g. See the response to Question No. 22(a). The depreciation associated with the forecasted capital used in the 2021 IRP is being provided. See attached.

h. Annual heat rates are provided in Volume I, Table 8-6.

i. Forced outage rates are provided in Volume III, Reserve Margin Analysis, Table 3.

j. The Companies do not calculate a planned outage rate.

k. The Companies do not have this data.

l. The Companies do not have this data.

m. The Companies do not have this data.

Coal Unit Fixed O&M Assumptions in 2021 IRP (Nominal $)

Unit	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	$18,100,849	$17,704,502	$18,473,350	$18,638,035	$19,569,527	$19,466,270	$0	$0	$0	$0	$0	$0	$0	$0	$0
Ghent 1	$18,021,906	$16,477,435	$17,044,736	$19,730,959	$19,196,971	$19,972,997	$20,987,153	$28,514,038	$20,776,616	$21,260,419	$21,755,946	$22,263,493	$0	$0	$0
Ghent 2	$9,064,946	$8,331,485	$10,459,297	$9,359,063	$8,581,369	$18,576,808	$10,129,886	$9,960,960	$11,700,155	$11,954,762	$12,215,079	$12,481,240	$0	$0	$0
Ghent 3	$22,490,711	$24,391,935	$23,057,976	$26,030,629	$33,099,635	$26,016,389	$26,324,903	$25,901,668	$29,330,294	$30,017,029	$30,720,503	$31,441,140	$35,753,761	$32,935,661	$33,710,452
Ghent 4	$22,803,362	$22,042,441	$24,798,911	$23,633,983	$26,890,383	$27,105,052	$34,888,937	$27,159,185	$27,563,738	$28,215,142	$28,882,578	$29,566,457	$30,267,200	$30,985,240	$31,721,995
Mill Creek 1	$2,541,278	$4,984,578	$2,773,347	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mill Creek 2	$8,641,610	$7,075,240	$9,829,217	$9,075,463	$12,529,326	$9,981,762	$0	$0	$0	$0	$0	$0	$0	$0	$0
Mill Creek 3	$23,558,958	$31,472,456	$24,070,298	$30,095,562	$26,149,334	$36,389,645	$28,034,198	$32,911,671	$29,559,832	$36,491,828	$31,144,440	$37,321,526	$32,705,086	$43,013,656	$34,347,199
Mill Creek 4	$36,104,829	$24,772,420	$30,003,141	$25,101,295	$30,765,621	$26,492,559	$31,237,440	$28,224,184	$38,675,893	$29,813,137	$41,141,060	$31,311,189	$39,559,665	$32,887,645	$38,375,006
Trimble County 1	$11,918,910	$15,489,793	$12,770,273	$18,688,285	$13,257,429	$16,115,110	$14,013,610	$16,681,005	$14,762,892	$15,987,235	$16,306,980	$21,896,305	$16,965,782	$17,305,098	$17,651,200
Trimble County 2	$19,675,876	$20,151,443	$22,188,910	$19,941,702	$24,007,253	$20,513,779	$23,316,996	$21,622,787	$24,398,581	$23,408,619	$23,876,791	$24,354,327	$28,128,323	$25,338,242	$25,845,007

VOM $/MWh	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Brown 3	$1.609	$1.623	$1.665	$1.703	$1.738	$1.772									
Ghent 1	$1.560	$1.596	$1.641	$1.681	$1.715	$1.749	$1.784	$1.820	$1.856	$1.894	$1.931	$1.970			
Ghent 2	$1.111	$1.147	$1.189	$1.217	$1.242	$1.267	$1.292	$1.318	$1.344	$1.371	$1.398	$1.426			
Ghent 3	$1.728	$1.770	$1.820	$1.866	$1.906	$1.944	$1.983	$2.023	$2.063	$2.104	$2.146	$2.189	$2.233	$2.278	$2.323
Ghent 4	$1.755	$1.791	$1.839	$1.882	$1.919	$1.957	$1.996	$2.036	$2.077	$2.119	$2.161	$2.204	$2.248	$2.293	$2.339
Mill Creek 1	$0.828	$0.851	$0.884												
Mill Creek 2	$0.844	$0.868	$0.902	$0.924	$0.945	$0.964									
Mill Creek 3	$1.483	$1.503	$1.540	$1.580	$1.619	$1.651	$1.684	$1.718	$1.752	$1.787	$1.823	$1.860	$1.897	$1.935	$1.973
Mill Creek 4	$1.357	$1.373	$1.408	$1.445	$1.480	$1.509	$1.540	$1.570	$1.602	$1.634	$1.667	$1.700	$1.734	$1.769	$1.804
Trimble 1	$1.546	$1.593	$1.636	$1.679	$1.715	$1.750	$1.785	$1.820	$1.857	$1.894	$1.932	$1.970	$2.010	$2.050	$2.091
Trimble 2	$1.596	$1.648	$1.700	$1.752	$1.801	$1.837	$1.874	$1.912	$1.950	$1.989	$2.029	$2.069	$2.111	$2.153	$2.196

Generation GWh	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Brown 3	1,038.1	990.8	1,106.3	928.5	921.2	944.4	-	-	-	-	-	-	-	-	-
Ghent 1	2,610.9	3,017.8	2,684.3	2,482.2	2,726.1	2,657.8	2,779.4	2,443.5	2,676.3	2,751.9	2,687.8	2,775.4	-	-	-
Ghent 2	2,627.7	2,855.1	2,327.7	2,659.6	2,566.6	2,318.9	2,687.4	2,650.0	2,486.1	2,600.1	2,681.3	2,623.2	-	-	-
Ghent 3	2,551.5	2,578.4	2,432.6	2,383.6	2,211.1	2,336.3	2,554.4	2,530.5	2,342.9	2,450.2	2,491.4	2,504.3	2,455.1	2,463.4	2,425.7
Ghent 4	2,213.2	2,449.1	1,928.8	1,963.3	1,896.3	1,991.0	1,982.2	2,031.5	2,118.6	2,068.6	2,118.8	2,127.6	2,217.2	2,260.9	2,267.3
Mill Creek 1	1,805.7	1,774.9	2,106.4	-	-	-	-	-	-	-	-	-	-	-	-
Mill Creek 2	789.6	813.5	930.5	2,043.2	1,984.4	2,085.4	-	-	-	-	-	-	-	-	-
Mill Creek 3	2,162.3	1,899.5	2,510.0	2,347.7	2,549.6	2,160.4	2,626.2	2,384.0	2,652.1	2,455.0	2,635.1	2,456.0	2,443.9	2,187.5	2,499.0
Mill Creek 4	2,571.8	2,924.8	3,096.6	3,410.0	3,393.0	3,054.8	3,109.5	3,448.9	2,926.8	3,419.6	3,227.3	3,396.4	2,963.9	3,243.5	2,996.1
Trimble County 1	2,412.7	2,407.3	2,509.2	2,196.0	2,465.2	2,419.8	2,567.6	2,424.4	2,531.5	2,344.4	2,531.5	2,156.7	2,520.8	2,391.6	2,521.9
Trimble County 2	3,390.2	2,978.1	3,190.8	3,153.6	2,894.0	3,268.1	3,383.0	3,314.1	3,272.2	3,252.0	3,279.6	3,232.3	2,934.3	3,253.9	3,199.2

Projected Annual Depreciation By Coal-Fired Unit ($)

	2021	2022	2023	2024	2025	2026	2027
Mill Creek 1	10,648,115	14,320,846	14,342,840	14,351,865			
Mill Creek 2	14,726,693	24,609,252	24,797,215	25,078,148	25,327,082	25,381,975	25,394,333
Mill Creek 3	17,003,789	25,819,768	26,188,122	26,556,877	26,960,600	27,399,781	28,231,463
Mill Creek 4	31,117,948	44,771,940	45,767,962	46,601,375	47,367,407	47,984,672	48,726,802
Ghent 1	24,408,231	31,251,000	31,598,874	31,984,361	32,588,191	33,223,041	33,565,381
Ghent 2	14,353,773	20,113,493	20,247,832	20,607,898	20,929,318	21,257,059	22,293,560
Ghent 3	21,967,968	27,078,169	27,515,932	28,077,724	28,599,192	29,384,307	29,960,838
Ghent 4	43,405,940	61,348,106	61,761,228	62,386,708	63,047,098	63,555,035	64,046,490
Trimble County 1	16,123,309	20,043,794	20,346,596	20,642,061	20,936,746	21,241,391	21,612,423
Trimble County 2	24,427,672	26,448,594	26,888,581	27,329,072	27,629,873	28,113,681	28,617,604
Brown 3	39,912,930	49,798,551	49,928,513	50,059,317	50,169,324	50,215,785	50,231,908

Projected Annual Depreciation By Coal-Fired Unit ($)

	2028	2029	2030	2031	2032	2033	2034
Mill Creek 1							
Mill Creek 2							
Mill Creek 3	29,021,960	29,333,821	29,730,600	30,054,972	30,396,500	30,694,605	30,940,990
Mill Creek 4	49,452,710	50,117,522	51,068,943	52,193,716	53,024,961	53,750,522	54,350,199
Ghent 1	33,908,333	34,613,802	35,107,258	35,186,866	35,263,813	35,285,222	
Ghent 2	23,084,313	23,169,620	23,388,964	23,593,496	23,637,871	23,650,218	
Ghent 3	30,291,927	30,800,882	31,291,117	31,735,286	32,182,796	32,600,082	33,168,436
Ghent 4	65,246,756	66,636,710	67,307,678	67,750,895	68,251,275	68,717,860	69,029,396
Trimble County 1	21,985,286	22,419,159	22,856,990	23,126,019	23,528,386	24,013,460	24,506,743
Trimble County 2	29,003,315	29,419,410	29,698,290	30,030,527	30,434,236	30,846,019	31,508,331
Brown 3							

Projected Annual Depreciation By Coal-Fired Unit ($)

	2035	2036
Mill Creek 1		
Mill Creek 2		
Mill Creek 3	31,629,298	32,241,262
Mill Creek 4	54,909,374	55,282,733
Ghent 1		
Ghent 2		
Ghent 3	33,559,806	33,588,085
Ghent 4	69,143,041	69,174,661
Trimble County 1	24,933,738	25,369,274
Trimble County 2	32,179,042	32,616,030
Brown 3		

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.19

Responding Witness: Stuart A. Wilson

Q-1.19. Refer to the 2021 IRP Long-Term Resource Planning Analysis.

a. Did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when existing units would have costs (fixed costs and variable costs) that exceed their revenues? If so, please provide any such analyses. If not, please explain in detail why not.

b. Did the Companies conduct or cause to be conducted any economic analysis, under any of the scenarios, of when it would be economic to retire any existing generating units? If so, please provide any such analyses. If not, please explain in detail why not.

c. Within the last five years, have the Companies prepared or caused to be prepared any analysis of whether to continue to operate or retire any of their existing generating units? If so, please produce any such analyses. If not, please explain in detail why not.

d. Have the Companies prepared or caused to be prepared any analysis of the reliability impacts of retiring existing units? If so, please produce any such analyses, including all supporting workpapers and modeling input and output files. If not, please explain in detail why not.

A-1.19.

a. No. The Companies are not members of a Regional Transmission Organization such as MISO or PJM, so revenues are not associated with individual units.

b. No. Except for the small-frame SCCTs, Mill Creek 1, Mill Creek 2, and Brown 3, all CO_2-emitting units were assumed to retire at the end of their book depreciation lives as a simplifying assumption.

c. Yes. See attached. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

d. Yes. See the 2021 IRP Reserve Margin Analysis in Vol. III of the 2021 IRP. See the response to Question No. 3. The related workpapers are at the following file path: \0283_2021IRP\ReserveMargin

Analysis of Generating Unit Retirement Years

PPL companies

Generation Planning & Analysis
October 2020

Contents

1. Summary

The Companies own and operate approximately 7,561 MW of summer net generating capacity in Kentucky. The generating system consists of four coal-fired generating stations: the E.W. Brown Generating Station in Mercer County, the Ghent Generating Station in Carroll County, the Mill Creek Generating Station in Jefferson County, and Trimble County Generating Station. The purpose of this study was to examine the existing retirement dates for certain coal-fired generating units as reflected in existing depreciation rates based on maintaining system reliability to determine whether they were reasonable based on the changes in operational and economic circumstances and, if not, to determine reasonable retirement years. This report explains the basis for the updates to the retirement years for the generating units shown in Table 1. The updated retirement years are estimates of the currently expected operating lives of these generating units. Actual retirement dates may vary depending on the circumstances involving the generating unit and operational factors that may emerge in the future. The Companies will continue to assess these retirement dates.[1]

Table 1 - Retirement Years, Current vs. Updated

	Retirement Years	
	Current	**Updated**
Brown Unit 3 (“BR3”)	2035	2028
Ghent Unit 4 (“GH4”)	2038	2037
Mill Creek Unit 1 (“MC1”)	2032	2024
Mill Creek Unit 2 (“MC2”)	2034	2028
Mill Creek Unit 3 (“MC3”)	2038	2039
Mill Creek Unit 4 (“MC4”)	2042	2039
Trimble Count Unit 1 (“TC1”)	2050	2045

2. Mill Creek Unit 1

As presented in LG&E’s 2020 ECR Plan, due to the cost of complying with Effluent Limitation Guidelines (“ELG”), MC1 will be retiring at the end of 2024.[2] Retiring MC1 on December 31, 2024 is lower cost than investing in the water treatment facilities that would be required to comply with ELG and continue its operation beyond December 31, 2024. As a result, it is no longer reasonable to continue to use 2032 as the retirement year for MC1. Based on current capacity and demand projections, the Companies are not planning for immediate replacement of MC1’s generating capacity.

3. Ghent Unit 4, Mill Creek Units 3 and 4, and Trimble County Unit 1

Based on their current retirement years, GH4, MC3, and MC4 would be the last coal-fired units to retire before the retirements of the newer Trimble County units. The Companies have decided to delay the

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[1] The results of this study were provided to Mr. John J. Spanos for purposes of independent assessment in connection with possible changes to existing depreciation rates.

[2] *Electronic Application of Louisville Gas and Electric Company for Approval of its 2020 Compliance Plan for Recovery by Environmental Surcharge*, Case No. 2020-00061, Direct Testimony of Stuart A. Wilson (Ky. PSC Mar. 31, 2020).

retirement year for MC3 by one year and to advance the retirement years by one year for GH4 and three years for MC4. These changes align the retirement years of Ghent Units 3 and 4 in 2037 and Mill Creek Units 3 and 4 in 2039 and reduce major maintenance costs on MC4 in 2038. This alignment also allows for planning a more orderly closure of the Ghent and Mill Creek stations and the potential for more cost-effective replacement of their collective capacities through economies of scale and coordinated procurement, construction or both. The Companies also are advancing the retirement year for TC1 to 2045, reflecting an expected age at retirement of 55 years, which better aligns with the expected lives of the Companies' other remaining coal units.

4. Mill Creek Unit 2 and Brown Unit 3

4.1. Mill Creek Unit 2 Background

2015 Ozone NAAQS

The Mill Creek station is in Jefferson County, Kentucky and currently operates four coal-fired units. Jefferson County is currently classified as marginal non-attainment to the 2015 Ozone National Ambient Air Quality Standard ("NAAQS") with a compliance date of August 2021. In 2020, the Kentucky Energy and Environment Cabinet and the Louisville Metro Air Pollution Control District ("LMAPCD") imposed additional daily limitations on nitrogen oxides ("NO_x") emissions at the Mill Creek station for the months of May through October. Despite the Companies' efforts to meet these limits, there were exceedances of the 70 ppb ozone standard in the Jefferson County area during the 2020 ozone season. LMAPCD has stated that Jefferson County will not be "in compliance" with the 2015 Ozone NAAQS by August 2021 due to these exceedances in 2020. LMAPCD currently anticipates reclassification to moderate non-attainment in 2022 and Title V facilities in Jefferson County will be required to implement NO_x Reasonable Available Control Technology ("RACT") by March 1, 2023. In the interim, the Companies expect that the ozone season NO_x limit for the MC station will remain in place pending development of the NO_x RACT standard. Therefore, LG&E will likely be limited to operating either MC1 or MC2 (but not both) during the ozone season (i.e., April through October) until MC1 retires.

Upon reclassification to moderate non-attainment with the 2015 Ozone NAAQS, Jefferson County will have a moderate non-attainment compliance date of August 3, 2024. The State Implementation Plan ("SIP") must be amended to include the RACT standards by April 2024. The NO_x emission reduction associated with the implementation of RACT at Mill Creek Station is expected to be similar to the mode of operation at Mill Creek during the summer of 2020. However, during the summer of 2020, there were still exceedances of the 70 ppb ozone standard in the Jefferson County area.

Continued non-attainment past the 2024 compliance date will result in Kentucky reevaluating RACT for the Jefferson County area in order to further reduce NO_x emissions or cause the non-attainment area to be reclassified to serious non-attainment. Such a reclassification would require additional NO_x emission reductions, which must be demonstrated by August 2027. LG&E will likely be required to install additional NO_x controls on MC2 such as selective catalytic reduction ("SCR") to achieve these reductions and continue to operate the unit.

2025 Ozone NAAQS

The Clean Air Act requires that NAAQS be evaluated every five years. The ozone and $PM_{2.5}$ NAAQS were reevaluated in 2020. EPA retained the current standard of 70 ppb for ozone and 12.0 $\mu g/m^3$ for $PM_{2.5}$. Prior to EPA's proposal to retain the current standards, many environmental groups and members on the Clean Air Scientific Advisory Committee presented data for a lower standard of 65 – 68 ppb for ozone and

10-11 µg/m^3 for PM$_{2.5}$. Both standards will be reevaluated again in 2025. At this time, there is every reason to expect both standards will be lowered following the reevaluation in 2025. Jefferson County is likely not to meet either standard. Therefore, even if Jefferson County has achieved attainment of the 70 ppb ozone standard by August 2024, it is likely that the standard would be lowered in 2025, and, once again, Jefferson County will be determined to be non-attainment for ozone. Such a determination will start the process of establishing a new RACT and implementing further NO$_x$ reductions at all sources, including the Mill Creek station. Based on the timeframe for implementing lowered NAAQS, it is likely additional controls would be required for MC2 by 2029.

CSAPR Requirements

An additional contingency arises under EPA's interstate transport rules for NO$_x$ that ensure that the northeastern states are meeting the ozone standards and are not exceeding these standards due to interstate transport. EPA's Cross-State Air Pollution Rule ("CSAPR") regulations were developed to accomplish this requirement. Currently certain areas in the northeastern states are not meeting the 2008 (75 ppb) ozone standard. To address this issue, on October 15, 2020, EPA issued the proposed Revised CSAPR Update rule, which will significantly reduce the NO$_x$ allowances issued to Kentucky. Based on their modeling, electric generating units in Kentucky have an impact exceeding a screening threshold on the northeastern non-attainment areas. Additional controls at our non-SCR-equipped units may be required because of the reduced allocation of NO$_x$ emissions allowances for Kentucky and the LG&E and KU fleet. Additional allowances will be limited under the proposed rule; and trading will be restricted to the twelve states EPA is assigning to the "Group 3" Trading Group. Because this allowance reduction was necessary to meet the 2008 (75 ppb) standard by 2021, it is reasonable to expect that even greater NO$_x$ reductions will be necessary in order to meet a 70 ppb ozone standard.

Regional Haze

A final environmental contingency is the possible changes from the Regional Haze 3rd Planning period. Mill Creek Units 3 and 4 have permit limits from the 1st planning period to meet the visibility criteria for Mammoth Cave National Park under the rule. Mill Creek did not have to take further restrictions for the 2nd planning period due to Kentucky visibility falling well below the glide path of visibility impaired days required by the regulation for 2030. EPA's requirements for implementation of the 3rd planning period of the Regional Haze regulation will likely be published in 2028 for states to model sources impacting visibility in national parks. Kentucky is not currently below the glide path required in the next planning period. Because Mill Creek is relatively close to Mammoth Cave National Park, Units 1 and 2 could be required in the next planning period to evaluate additional controls to improve visibility at the park.

In summary, the Companies expect that SCR will be required on MC2 between 2027 and 2029 to comply with current and future NAAQS. Uncertainty related to the EPA's CSAPR regulations and the Regional Haze rule further supports this assumption. Therefore, the Companies have assumed that SCR will be required on MC2 in 2028 to operate MC2 beyond 2028. The SCR investment is approximately $135 million. Additionally, an investment in major maintenance will be required in 2026 if MC2 is planned to remain in service beyond 2028. As of 2020, MC2 is 46 years old. Its current retirement year is 2034. This analysis will determine whether either of these future investments is economically warranted and if they are not, then the current 2034 retirement year is not reasonable, and a new date must be determined.

4.2. Brown Unit 3 Background

As of 2020, BR3 is 49 years old. BR3's current retirement year is 2035. Since the retirement of Brown Units 1 and 2 in 2019, BR3 is the single remaining coal unit at the Brown Station. BR3's delivered fuel cost is higher than that of the Companies' other coal units because coal is only delivered by rail. The higher delivered fuel cost causes BR3 to operate at a significantly lower capacity factor.[3] It is outfitted with full emissions controls and its last major maintenance overhaul was in 2019.[4] A total investment in major maintenance of approximately $31 million will be required in 2026 and 2027 to continue its operation beyond 2028. An evaluation of those investments is necessary to determine if BR3's current retirement year is reasonable, or if a new retirement year should be set based on the ability to operate the unit absent these major maintenance investments.

4.3. Analysis Methodology

Given the expectations regarding compliance with environmental regulations, forecasts for required future investments, the resultant physical life of the units, and the need for replacement generation, the Companies evaluated advancing the retirement years for MC2 and BR3. The analysis was performed to determine whether the existing retirement years are reasonable and if not to determine reasonable retirement years based on current information.

Before committing to actual retirement dates, the Companies plan to evaluate the ability to replace the units as needed to continue to supply reliable, reasonable cost energy based on actual proposals from third party suppliers (gathered via a request for proposals) and self-build alternatives. The results of this process would be filed with the Kentucky Public Service Commission in an application for a Certificate of Public Convenience and Necessity.

As set forth above, MC2 is expected to require an approximately $135 million investment in SCR on or before 2028 to continue operation beyond 2028. Accordingly, the Companies are advancing the MC2 retirement year to 2028. Likewise, a 2028 retirement year was selected for BR3 because 2028 is the longest BR3 can operate without the investments in 2026 and 2027 for major maintenance. The present value of revenue requirements ("PVRR") for each alternative was computed as the PVRR of the following cost and revenue items:

1. Generation system production costs
2. Existing unit stay-open costs, including ELG compliance costs and associated O&M
3. Existing unit revenues from the sale of coal combustion residuals ("CCR")
4. Capital and stay-open costs for replacement generation units

Generation production costs for the LG&E and KU system were computed using the PROSYM production cost model from Hitachi ABB. The PVRR for all alternatives include the full PVRR for capital expenditures, even when a unit is retired before it is fully depreciated. The analysis also assumes that MC2 and BR3 would otherwise be retired by their current retirement years, 2034 and 2035, respectively. Therefore, later retirement is assumed to defer the cost of any replacement generation, but not eliminate this cost altogether. The Companies initially evaluated the retirement year for MC2, given the NAAQS compliance issues and the high cost of investing in a SCR. The Companies then evaluated the retirement year for Brown 3.

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[3] BR3's capacity factor was 28%, 35%, and 25%, in 2017, 2018, and 2019, respectively. It is forecasted to operate at a capacity factor of 24%, 22%, and 26% in 2021, 2022, and 2023, respectively.

[4] BR3's emissions controls include low NO_x burners, SCR, dry electrostatic precipitator, dry sorbent injection, powdered activated carbon injection, pulse jet fabric filter, and dry flue gas desulfurization.

For this analysis, the Companies assumed that MC2 and BR3 would be replaced with capacity from simple-cycle combustion turbines ("CTs") to create a generation portfolio that is minimally compliant for reliability, obviating the need to consider a range of fuel prices or a range of potential replacement alternatives. The point of this study was not to identify a potentially optimal future portfolio. As mentioned above, the Companies will issue a request for proposals to determine the optimal replacement resources and help inform the actual retirement dates for each of these units. The goal of this study is to determine whether the current estimated retirement years for MC2 and BR3 are reasonable given current information regarding the likely costs of operating the units to the currently projected dates.

4.4. Analysis

A primary consideration when contemplating unit retirements is the need to maintain a sufficient reserve margin for summer peak reliability. The following tables show the calculation of annual forecasted summer reserve margins and include the following assumptions:

- The Companies' 2021 Business Plan peak demand forecast;
- MC2 (297 MW) is unavailable from April through October in 2021-2024 due to the expected continuing limitation on NO_x emissions from the Mill Creek station;
- MC1 (300 MW) retires at the end of 2024; and
- Zorn (14 MW) retires at the end of 2021; the Companies remaining small-frame CTs (59 MW)[5] retire at the end of 2025.
- For presentation purposes, no additional retirements beyond 2030 are assumed.

Table 2 shows the forecasted summer reserve margins through 2035 with no coal unit retirements after MC1's retirement at the end of 2024. Table 3 shows the reserve margins assuming that MC2 retires in 2028 without replacement. Because the reserve margin remains above the lower end of the Companies' target reserve margin range of 17 percent to 25 percent, it is assumed that MC1 and MC2 can be retired without replacement. Table 4 shows the reserve margins assuming that BR3 also retires in 2028 without replacement. To maintain a 17 percent reserve margin in 2028, 278 MW of replacement capacity is needed. As a proxy for commercially available replacement capacity, the Companies assumed that two CTs similar to the Companies' existing CTs at the Trimble County station would provide this replacement capacity with net summer ratings of 159 MW each. Table 5 shows that the forecasted reserve margins with this additional 318 MW of capacity are within the Companies' target reserve margin range.

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[5] The remaining small-frame CTs are Haefling 1 (12 MW), Haefling 2 (12 MW), Paddy's Run 11 (12 MW), and Paddy's Run 12 (23 MW).

Table 2 - Reserve Margin with MC1 and Small Frame CTs Retirements (MW)

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Gross Peak Load	6,399	6,433	6,430	6,428	6,420	6,406	6,391	6,369	6,358	6,344	6,332	6,324	6,325	6,320	6,320
Energy Efficiency/Demand Side Mgmt.	(288)	(294)	(300)	(305)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)	(311)
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Existing Generation Resources	7,711	7,712	7,712	7,712	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713	7,713
Curtailable Load (CSR)	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Direct Load Control (DLC)	63	61	60	58	56	55	53	52	50	49	48	47	46	45	44
Small-Frame CT Retirements	0	(14)	(14)	(14)	(14)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)	(73)
MC2 Unavailable	(297)	(297)	(297)	(297)											
MC1 Retirement					(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
Total Resources Net of MC1 and Small-Frame CTs Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,519**	**7,517**	**7,516**	**7,515**	**7,514**	**7,513**	**7,512**	**7,511**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**24.1%**	**24.3%**	**24.6%**	**24.8%**	**25.0%**	**24.9%**	**25.0%**	**25.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 3 - Reserve Margin with Incremental MC2 Retirement in 2028 (MW)

	2021	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Total Resources Net of MC1 and Small-Frame CTs Retirements	7,604	7,589	7,588	7,586	7,582	7,522	7,520	7,519	7,517	7,516	7,515	7,514	7,513	7,512	7,511
MC2 Retirement in 2028								(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,222**	**7,220**	**7,219**	**7,218**	**7,217**	**7,216**	**7,215**	**7,214**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**19.2%**	**19.4%**	**19.7%**	**19.9%**	**20.0%**	**20.0%**	**20.1%**	**20.0%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

Table 4 - Reserve Margin with Incremental BR3 Retirement in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Totals Resources Net of MC1, Small-Frame CTs, and MC2 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,222**	**7,220**	**7,219**	**7,218**	**7,217**	**7,216**	**7,215**	**7,214**
BR3 Retirement in 2028								(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**6,810**	**6,808**	**6,807**	**6,806**	**6,805**	**6,804**	**6,803**	**6,802**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**12.4%**	**12.6%**	**12.8%**	**13.0%**	**13.2%**	**13.1%**	**13.2%**	**13.2%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**278**	**267**	**252**	**239**	**231**	**233**	**228**	**229**

Table 5 - Reserve Margin with Capacity Addition in 2028 (MW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Net Peak Load	**6,111**	**6,139**	**6,130**	**6,123**	**6,109**	**6,095**	**6,080**	**6,058**	**6,047**	**6,033**	**6,021**	**6,013**	**6,014**	**6,009**	**6,009**
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**6,810**	**6,808**	**6,807**	**6,806**	**6,805**	**6,804**	**6,803**	**6,802**
Additional 2 CTs								+318	+318	+318	+318	+318	+318	+318	+318
Totals Resources Net of MC1, Small-Frame CTs, MC2, and BR3 Retirements	**7,604**	**7,589**	**7,588**	**7,586**	**7,582**	**7,522**	**7,520**	**7,128**	**7,126**	**7,125**	**7,124**	**7,123**	**7,122**	**7,121**	**7,120**
Reserve Margin %	**24.4%**	**23.6%**	**23.8%**	**23.9%**	**24.1%**	**23.4%**	**23.7%**	**17.7%**	**17.8%**	**18.1%**	**18.3%**	**18.5%**	**18.4%**	**18.5%**	**18.5%**
Reserve Margin Deficit vs. 17%	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**	**NA**

4.4.1. Mill Creek Unit 2

MC2's current retirement year is 2034. As discussed in Section 4.1, the Companies expect that SCR will be required for MC2 by 2028 in order to continue operating beyond 2028. The cost of SCR for MC2 is estimated to be at least $135 million in 2020 dollars. Furthermore, an investment in major maintenance in 2026 of $5.5 million in capital and $5.0 million in O&M costs would be required for MC2 to continue operating until 2034. Table 6 shows the difference in annual revenue requirements and PVRR between retiring MC2 in 2028 and 2034, assuming that the SCR and major maintenance expenditure could be avoided with the earlier retirement date. It is assumed that MC2 would otherwise retire in 2034, so there are no differences in revenue requirements in 2034 and beyond. Additional savings from retiring MC2 in 2028 result from avoiding MC2's stay-open costs, which are partially offset by production cost increases and foregone CCR sales revenue. Because MC2 can be retired without replacement as shown in Table 3, there are no incremental costs for new capacity to replace MC2. The total net PVRR ("NPVRR") impact of retiring MC2 in 2028 is a savings of $131.2 million.

Table 6 – Revenue Requirement Increases/(Savings) of Retiring MC2 in 2028 vs. 2034 ($M)[6]

	2026	2027	2028	2029	2030	2031	2032	2033
Production Costs	0	0	14.2	13.9	15.2	16.2	16.6	15.4
Stay Open Costs	0	0	(26.9)	(22.3)	(30.6)	(23.0)	(31.9)	(24.0)
SCR Cost	0	0	(166.1)	0	0	0	0	0
Major Maintenance	(11.7)	0	0	0	0	0	0	0
CCR Revenue	0	0	2.9	3.0	3.1	3.2	3.2	3.1
Total	**(11.7)**	**0**	**(175.9)**	**(5.5)**	**(12.3)**	**(3.6)**	**(12.1)**	**(5.5)**
NPVRR (2020)	**(131.2)**							

As a result of the likely need for the uneconomic investment in SCR in order to operate MC2 beyond 2028, it is unreasonable to continue to use 2034 as the retirement year. Given that compliance with likely additional NAAQS ozone standards would be required by 2028, that year represents a reasonable retirement year.

4.4.2. Brown Unit 3

BR3's current retirement year is 2035. An investment in major maintenance in 2026 and 2027 of $23.1 million in capital and $8 million in O&M costs would be required for BR3 to continue operating until 2035. Given the savings from retiring MC2 in 2028, the analysis of BR3's retirement year assumes that MC2 will retire in 2028. As shown in Table 4, retiring MC2 and BR3 in 2028 results in a minimum capacity need of 278 MW in 2028 to maintain a reserve margin within the Companies' target reserve margin range. To meet this reserve margin deficit, the Companies modeled replacement capacity comprising two CTs with the same characteristics as their existing Trimble County CTs, for a total additional capacity of 318 MW.

Table 7 shows the difference in annual revenue requirements and PVRR between retiring BR3 in 2028 and 2035. It is assumed that BR3 would otherwise retire in 2035, so there are no differences in revenue

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[6] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

requirements in 2035 and beyond. In addition to the savings from avoiding the major maintenance investments in 2026 and 2027, retiring BR3 in 2028 results in the savings of its stay open costs through 2034 and a small amount of additional CCR revenue achieved by transferring some of BR3's generation to other coal units with more favorable CCR sales opportunities. These savings are more than offset on an annual basis by increases in production costs and the carrying cost of the required capacity additions. The NPVRR impact of retiring BR3 in 2028 is a revenue requirements savings of $40 million. Therefore, the existing 2035 retirement date is unreasonable and replacing it with 2028 is more reasonable given the potential to avoid major maintenance and lower overall revenue requirements with replacement generation by 2028.

Table 7 - Revenue Requirement Increases/(Savings) of Retiring BR3 in 2028 vs. 2034 ($M)[7]

	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**
Production Costs	0	0	3.3	5.7	5.4	6.1	6.8	7.8	5.0
Stay Open Costs	0	0	(40.3)	(39.5)	(40.5)	(41.3)	(42.1)	(43.0)	(43.8)
Major Maintenance	(13.9)	(22.1)	0	0	0	0	0	0	0
CCR Revenue	0	0	(0.1)	(0.1)	(0.2)	(0.2)	(0.3)	(0.2)	(0.1)
Capacity Additions	0	0	29.5	30.1	30.6	31.2	31.7	32.3	32.9
Total	**(13.9)**	**(22.1)**	**(7.5)**	**(3.9)**	**(4.7)**	**(4.2)**	**(3.9)**	**(3.0)**	**(6.0)**
NPVRR (2020)	**(40.0)**								

The analysis focused only on maintaining system reliability. Therefore, when the Companies evaluate actual potential replacement alternatives for BR3, resource additions with the potential to lower energy costs (e.g., renewables and natural gas combined cycle) will provide additional information on the retirement date for BR3.

5. Appendix - Key Analysis Inputs and Assumptions

5.1. Existing Unit Stay-Open Costs

Stay-open costs for an existing unit include the unit's ongoing capital and fixed operating and maintenance ("O&M") costs. These costs are required to continue operating the unit and saved if the unit is retired. Table 8 lists total stay-open costs for the Companies' coal units assuming no early retirements. Costs that are shared by all units are allocated to units in proportion to how they would be reduced as units retire. Total stay-open costs include costs for regular maintenance and major maintenance; the analysis assumes the additional costs for major maintenance within eight years of retirement can be avoided. Beyond 2030, stay-open costs are assumed to escalate at two percent per year.

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[7] For presentation purposes, the PVRR is shown for capital expenditures in the year incurred rather than the annual revenue requirements.

Table 8 – Stay-Open Costs ($M, Nominal Dollars)

Total Stay-Open Costs	2026	2027	2028	2029	2030	2031	2032	2033	2034
MC2 – major maintenance	10.5	-	-	-	-	-	-	-	-
MC2 – annual	26.0	19.5	25.0	20.6	28.2	21.2	29.3	22.0	-
BR3 – major maintenance	11.4	19.6	-	-	-	-	-	-	-
BR3 – annual	35.8	37.1	38.7	37.9	38.9	39.7	40.4	41.3	42.1

5.2. CCR Revenue Assumptions

Coal combustion residuals (“CCR”) include fly ash, bottom ash, and gypsum. CCR is either used for onsite construction projects, sold to third parties for use in the production of products like cement and wallboard, or stored in an onsite landfill. When sold to a third party, the beneficial use of CCR materials is included in the Environmental Surcharge Mechanism as a credit to offset environmental compliance costs. In 2019, CCR sales revenues totaled $9 million.

In recent years, as coal units have retired in the U.S., the market supply of CCR has decreased and the market price for CCR has increased. Table 9 lists the assumed sales prices for fly ash and gypsum from Mill Creek, Ghent, and Trimble County in this analysis. The sales prices are weighted average prices based on existing contracts rolling to market prices as existing contracts expire. The current market price for Mill Creek, Ghent, and Trimble County gypsum is approximately $10 per ton. The current market price for Mill Creek fly ash is approximately $32 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $25.60 per ton. The current market price for Ghent fly ash is approximately $30 per ton; based on current contracts, the Companies expect to receive 80% of market value for Mill Creek fly ash, or $24 per ton. The current market price for Trimble fly ash is approximately $9 per ton. CCR market prices are assumed to escalate at two percent per year.

Because Brown has no local market for either fly ash or gypsum, and because additional CCR loading systems at Brown are not economical, CCR revenue from Brown is assumed to be zero.

Table 9 – Sales Price for CCR Sales ($/ton) (Confidential and Proprietary Information)

	Mill Creek		Ghent		Trimble	
Year	Fly Ash	Gypsum	Fly Ash	Gypsum	Fly Ash	Gypsum
2021	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 10 lists the percent of fly ash and gypsum produced at Brown and Mill Creek that is assumed to be sold to third parties.

Table 10 – Percent of CCR Production Sold to Third Parties

Station	Fly Ash	Gypsum
Brown	0%	0%
Mill Creek	80%	97%

5.3. Fuel Prices

Fuel prices are assumed to escalate throughout the analysis period. Table 11 shows undelivered natural gas and coal price forecasts, which were developed for the Companies' 2021 Business Plan.

The Henry Hub natural gas price forecast reflects a blend of NYMEX market prices and a smoothed version of the Energy Information Administration's ("EIA's") 2020 Annual Energy Outlook ("AEO") High Oil and Gas Resource and Technology case through 2030, after which the smoothed EIA case was solely used. This case assumes higher resource availability and technological advancement, which results in lower production costs and continued growth in oil and gas production, compared to EIA's AEO 2020 Reference Case.

The Illinois Basin FOB mine coal price reflects a blend of coal price bids the Companies received, and a long-term price forecast developed by S&P Global Platts through 2025. In 2026 and beyond, the 2025 price was escalated by the coal escalation rate provided in the EIA's 2020 AEO High Oil and Gas Resource and Technology case.

Table 11 – Fuel Prices, Undelivered (Nominal $/mmBtu) (Confidential and Proprietary Information)

	Natural Gas[8]	**Coal[9]**
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]
2030	[redacted]	[redacted]
2031	[redacted]	[redacted]
2032	[redacted]	[redacted]
2033	[redacted]	[redacted]
2034	[redacted]	[redacted]
2035	[redacted]	[redacted]
2036	[redacted]	[redacted]
2037	[redacted]	[redacted]
2038	[redacted]	[redacted]
2039	[redacted]	[redacted]
2040	[redacted]	[redacted]
2041	[redacted]	[redacted]
2042	[redacted]	[redacted]
2043	[redacted]	[redacted]
2044	[redacted]	[redacted]
2045	[redacted]	[redacted]
2046	[redacted]	[redacted]
2047	[redacted]	[redacted]
2048	[redacted]	[redacted]
2049	[redacted]	[redacted]
2050	[redacted]	[redacted]

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[8] Henry Hub.

[9] Illinois Basin FOB mine.

5.4. Replacement CT Assumptions

Table 12 shows the assumed characteristics of the CTs that were modeled as replacement capacity.

Table 12 – Replacement CT Assumptions (2020 In-Service; 2019 Dollars)

	Peaking Capacity (SCCT)
Capital Cost ($/kW)	586
Fixed O&M ($/kW-yr)	12.7
Firm Gas Cost ($/kW-yr)	22.7
Start Cost - maintenance ($/Start)	11,147
Heat Rate (MMBtu/MWh)	10.9
Transmission Cost ($/MW-Yr)	N/A
Nominal O&M Cost Escalation	2%
Summer Net Capacity (MW)	159
Winter Net Capacity (MW)	179

5.5. Financial Assumptions

Table 13 lists the inputs used to compute capital revenue requirements in this analysis.

Table 13 – Financial Assumptions

	Combined Companies
% Debt	47%
% Equity	53%
Cost of Debt	4.02%
Cost of Equity	10.0%
Tax Rate	24.95%
Property Tax Rate	0.15%
Insurance Rate	0.0254%
WACC (After-Tax)	6.75%

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.20

Responding Witness: Stuart A. Wilson

Q-1.20. Please refer to Table 5-4 on page 5-18 of the IRP.

a. Did the Companies evaluate early retirement dates for Ghent 1 or Ghent 2?

b. If an analysis was performed, please provide the results of any analysis performed to evaluate the early retirement of Ghent 1and Ghent 2.

A-1.20.

a. No. See the response to Question No. 19(b).

b. Not applicable.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.21

Responding Witness: Stuart A. Wilson

Q-1.21. Please refer to page 3 of the 2021 IRP Reserve Margin Analysis where it says "To evaluate operating at lower reserve margins with less reliability, the Companies compared the reliability and production cost benefits for their marginal baseload and peaking resources to the savings that would be realized from retiring these resources. Specifically, the Companies evaluated the retirements of one or more Brown 11N2 simple-cycle combustion turbines ("SCCTs"), Mill Creek 2, and Brown 3."

a. Please explain if any other analysis was done outside of reserve margin analysis modeling to evaluate retirement dates. If other analysis was performed to evaluate the retirement of units, please provide the results of that analysis.

A-1.21.

a. The Companies performed no other analysis of retirement dates in the 2021 IRP. The Companies evaluated retirement dates as part of their 2020 rate case filings, Case Nos. 2020-00349 and 2020-00350, in Exhibit LEB-2, "Analysis of Generating Unit Retirement Years, October 2020."[4] See the response to Question No. 19(c).

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[4] See pages 140-155 at https://psc.ky.gov/pscecf/2020-00349/rick.lovekamp%40lge-ku.com/11252020084757/10-KU_Testimony_1of4%28Thompson_Blake_Bellar_Sinclair_Wolfe_Saunders%29.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.22

Responding Witness: Stuart A. Wilson

Q-1.22. Please confirm if the Companies are modeling the thermal resources on a UCAP or ICAP basis, and provide the following information for each of the Companies' thermal units:

a. Forecasted annual capital expenditures

b. Summer and Winter capacity contributions

c. Forced outage rates for the last five years

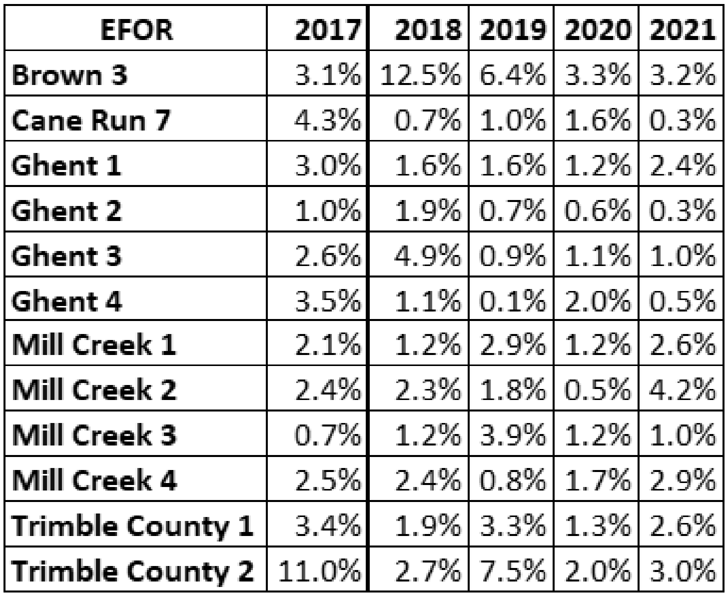
d. Forecasted forced outage rates

A-1.22. The Companies are modeling thermal resources on an ICAP basis.

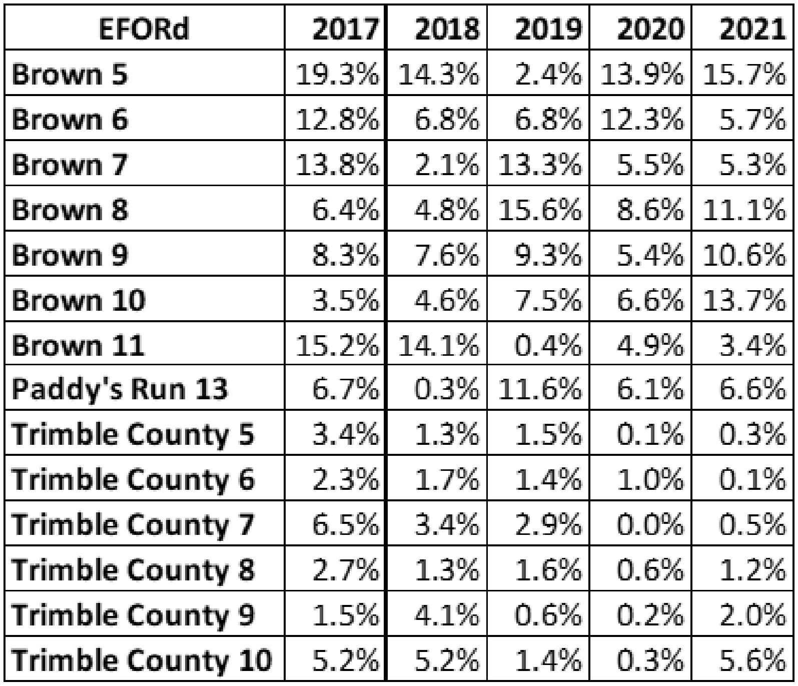
a. See attached. These costs reflect the stay-open capital used in the 2021 IRP. The costs do not include all capital items in the Companies' current Business Plan.

b. Summer and winter capacity contributions can be found in Table 3 in the Reserve Margin Analysis in Vol. III of the IRP.

c.



EFOR	2017	2018	2019	2020	2021
Brown 3	3.1%	12.5%	6.4%	3.3%	3.2%
Cane Run 7	4.3%	0.7%	1.0%	1.6%	0.3%
Ghent 1	3.0%	1.6%	1.6%	1.2%	2.4%
Ghent 2	1.0%	1.9%	0.7%	0.6%	0.3%
Ghent 3	2.6%	4.9%	0.9%	1.1%	1.0%
Ghent 4	3.5%	1.1%	0.1%	2.0%	0.5%
Mill Creek 1	2.1%	1.2%	2.9%	1.2%	2.6%
Mill Creek 2	2.4%	2.3%	1.8%	0.5%	4.2%
Mill Creek 3	0.7%	1.2%	3.9%	1.2%	1.0%
Mill Creek 4	2.5%	2.4%	0.8%	1.7%	2.9%
Trimble County 1	3.4%	1.9%	3.3%	1.3%	2.6%
Trimble County 2	11.0%	2.7%	7.5%	2.0%	3.0%



EFORd	2017	2018	2019	2020	2021
Brown 5	19.3%	14.3%	2.4%	13.9%	15.7%
Brown 6	12.8%	6.8%	6.8%	12.3%	5.7%
Brown 7	13.8%	2.1%	13.3%	5.5%	5.3%
Brown 8	6.4%	4.8%	15.6%	8.6%	11.1%
Brown 9	8.3%	7.6%	9.3%	5.4%	10.6%
Brown 10	3.5%	4.6%	7.5%	6.6%	13.7%
Brown 11	15.2%	14.1%	0.4%	4.9%	3.4%
Paddy's Run 13	6.7%	0.3%	11.6%	6.1%	6.6%
Trimble County 5	3.4%	1.3%	1.5%	0.1%	0.3%
Trimble County 6	2.3%	1.7%	1.4%	1.0%	0.1%
Trimble County 7	6.5%	3.4%	2.9%	0.0%	0.5%
Trimble County 8	2.7%	1.3%	1.6%	0.6%	1.2%
Trimble County 9	1.5%	4.1%	0.6%	0.2%	2.0%
Trimble County 10	5.2%	5.2%	1.4%	0.3%	5.6%

d. Forecasted forced outage rates can be found in the EFOR column of Table 3 in the Reserve Margin Analysis in Vol. III of the IRP.

Thermal Unit Capital Expenditure Assumptions in 2021 IRP (Nominal $)

Unit(s)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Mill Creek 1	527,513	302,840	37,902	0	0	0	0	0	0	0	0	0	0	0	0
Mill Creek 2	3,680,363	2,564,861	6,769,410	1,501,651	322,219	88,384	0	0	0	0	0	0	0	0	0
Mill Creek 3	3,373,446	13,040,102	3,391,279	14,598,289	4,971,255	32,087,769	3,136,133	10,760,144	6,920,000	7,533,743	7,684,418	5,598,925	5,379,768	25,290,671	1,977,911
Mill Creek 4	32,529,368	10,426,917	25,516,447	7,520,896	19,100,412	12,906,078	18,400,796	10,271,132	30,761,650	17,747,433	18,102,382	13,189,533	12,673,259	11,442,756	4,659,416
Ghent 1	6,709,716	7,757,670	8,273,993	16,838,102	9,564,034	4,673,216	9,589,478	19,749,609	772,267	2,538,447	661,617	228,770	0	0	0
Ghent 2	2,200,475	3,832,969	12,338,253	2,097,374	12,622,079	33,929,202	1,585,038	2,246,234	7,604,965	1,580,928	412,051	142,476	0	0	0
Ghent 3	4,992,669	18,652,060	11,691,812	16,474,053	25,932,055	5,207,921	12,675,022	14,814,997	11,663,860	12,326,868	11,844,361	10,694,339	20,003,924	1,134,993	392,451
Ghent 4	5,881,183	11,686,379	14,911,479	13,170,900	8,428,560	12,470,004	38,569,998	20,536,316	7,995,873	10,851,439	10,426,684	9,414,311	3,833,447	999,143	345,478
Trimble County 1	3,963,817	15,576,393	3,490,315	15,526,053	4,133,083	19,810,026	4,251,287	23,747,076	4,506,680	12,854,089	13,111,171	18,191,246	13,640,862	13,913,679	14,191,953
Trimble County 2	17,500,694	20,189,464	17,543,844	8,223,358	33,220,568	9,946,479	23,094,229	12,549,316	11,340,071	17,120,048	17,462,449	17,811,698	38,923,190	18,531,290	18,901,916
Brown 3	3,066,700	2,173,867	3,100,621	1,335,295	538,185	111,940	0	0	0	0	0	0	0	0	0
Cane Run 7	3,706,727	3,780,862	3,856,479	3,933,609	4,012,281	4,092,526	4,174,377	4,257,864	4,343,022	4,429,882	4,518,480	4,608,849	4,701,026	4,795,047	4,890,948
Brown 5, 8-11	1,582,703	1,614,358	1,646,645	1,679,578	1,713,169	1,747,432	1,782,381	1,818,029	1,854,389	1,891,477	1,929,307	1,967,893	2,007,251	2,047,396	2,088,344
Brown 6-7	346,403	353,331	360,398	367,606	374,958	382,457	390,107	397,909	405,867	413,984	422,264	430,709	439,323	448,110	457,072
Paddy's Run 13	1,731,874	1,766,512	1,801,842	1,837,879	1,874,637	1,912,129	1,950,372	1,989,379	2,029,167	2,069,750	2,111,145	2,153,368	2,196,435	2,240,364	2,285,171
Trimble County 5-10	9,522,265	9,712,710	9,906,964	10,105,104	10,307,206	10,513,350	10,723,617	10,938,089	11,156,851	11,379,988	11,607,588	11,839,739	12,076,534	12,318,065	12,564,426

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.23

Responding Witness: Stuart A. Wilson

Q-1.23. Please refer to Table 8-4 on page 8-13 of the IRP. Please explain what is driving the increase in capacity factor for Mill Creek 2 between 2025 and 2028.

A-1.23. As stated in Section 6 of Vol. I of the IRP, on pages 6-9 and 6-10, the Louisville Metro Air Pollution Control district imposed an additional 15-ton total daily NO_x emissions limitation on the Mill Creek Generating Station during the months of May through October, which effectively limits the Companies to operating either Mill Creek 1 or Mill Creek 2, but not both simultaneously. To preserve run hours on Mill Creek 2, the Companies are electing to primarily operate Mill Creek 1 during these months until the retirement of Mill Creek 1 at the end of 2024, at which point Mill Creek 2 will resume year-round availability until its expected retirement in 2028.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.24

Responding Witness: Stuart A. Wilson

Q-1.24. Please provide the most recent condition assessment report for each of the Companies' generating units.

A-1.24. See attached.

Generation Services Engineering 2018 Steam Only Depreciation Study Evaluation

5/25/18

Reviewed February 2022

Methodology

Many factors influence the end of life for a generating station. To complete this analysis the following assumptions were made regarding factors outside the direct technical evaluation:

- All necessary environmental permits and licenses will be maintained
- Future changes in environmental regulations are a consideration for unit retirement
- Units will continue to operate in a manner that is consistent with recent operating practices, with a similar number of annual starts and stops, and annual generation
- Units will continue to be operated in accordance with good industry practices with required renewals and replacements made in a timely manner

The steam generating units were reviewed at a high level and although many individual components could fail it was decided that those would not constitute an “end of life” event and could be mitigated. The boiler drum and turbine/generator were the two components/systems identified where catastrophic failure would be consideration for retirement.

Although the boiler is a complex system with many elements, the boiler drum is a large single component with approximately 240k hours of defined life and is significantly influenced by thermal cycling. Electric Power Research Institute (EPRI) studies indicate that after approximately 1,700 normal start/stop cycles the risk of a critical flaw developing is greatly increased.

The turbine/generator is a single system, whose failure could lead to significant downtime and repair/replacement costs. Several key factors are taken into consideration when evaluating the generator such as insulation type, winding age, recent inspection findings, and test results. Wear, cracking, and blade condition are key considerations for the turbine.

Review

The depreciation review process conducted by Generation Engineering consisted of evaluating key parameters (e.g., pressures, temperatures, voltages etc.) with equipment condition (e.g., inspection data, EPRI, IEEE, etc.) to provide a risk-based assessment regarding the likelihood of equipment failure as compared to industry norms.

Boiler

EPRI states:

- A critical flaw size crack appears on average at around 30 years of service (240,000 hours).
- The average number of cycles of a coal drum unit is expected to be 1,700 normal starts/stops to drive a critical flaw to failure.
- Natural Circulation boilers are more susceptible to ligament cracking than are Forced Circulation boilers.

The boiler review included previous inspection reports and a review of design vs typical operating temperatures and pressures.

Generator

Generators are regularly inspected and electrically tested. Those results were reviewed along with any other known issues. In most cases where the generator winding was beyond design life, no known issues have been observed and no concerns exist regarding condition.

Turbine

Turbines are inspected on a routine basis with periodic repairs/overhauls to bring the unit to as designed operation. To-date, no issues have been observed which did not allow a return to as designed operation.

Summary

Based on EPRI's research and the Generation Services Engineering review of units comparing their data, the boiler drum should not reduce the retirement year of each unit. While the EPRI “average end of drum life” for MC3 & MC4 are just short of the previous end of life depreciation study, the difference is not significant when considering these are typical and average numbers used from the analysis.

There are no known concerns regarding generator or turbine condition impacting unit end of life across the fleet.

The analysis in this summary supports continued operation of the existing steam units through the retirement dates presently anticipated considering economic, regulatory, and other factors.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.25

Responding Witness: Stuart A. Wilson

Q-1.25. Refer to the 2021 IRP, Volume I, Table 8-3, column entitled "Upgrades, Derates, Retirements."

a. For each unit, please specify the month of the upgrade, derate, or retirement and whether the date indicated corresponds to an upgrade, derate, or retirement.

b. Please specify for which units the retirement date is the end of the unit's book depreciation life. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format, with formulas intact).

A-1.25.

a. Note that the referenced column label is taken from 807 KAR 5:058 Sec. 8(3)(b)(11). All dates in Table 8-3 for the Companies are unit retirements. Months are not yet determined but for simplicity Mill Creek 1 is assumed to retire at the end of its retirement year while all other units will retire at the beginning of the retirement year.

b. For all units except for Mill Creek 1, Mill Creek 2, and Brown 3, the assumed retirement date is the unit's book depreciation life. See the response to Question No. 19(c).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.26

Responding Witness: Philip A. Imber

Q-1.26. For each of the Companies' existing coal-fired units, please produce the most recent estimate that the Companies have prepared or caused to be prepared of the capital and O&M costs to comply with the following regulations:

a. Acid deposition control program

b. Cross State Air Pollution Rule

c. Mercury and Air Toxics Standards

d. Combustion turbine NESHAP rule

e. NAAQS

f. Regional Haze rule

g. Greenhouse gas regulations

h. 316(b) cooling water intake rule

i. Effluent Limitations Guidelines

j. Any new definition of waters of the United States

k. Coal Combustion Residuals rule

l. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

A-1.26.

a. - l. While the IRP analysis contains capital and O&M inputs, it is not by equipment or system, therefore estimated expenses by regulation are not available other than from the Company's Business Plan. Please see the Company's response to Question No. 1-27 for capital and O&M estimates from the Company's Business Plan.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.27

Responding Witness: Philip A. Imber

Q-1.27. For each of the Companies' existing coal-fired units, please provide the capital and O&M costs projected to be incurred each year from 2021 through 2036 to comply with the following regulations:

a. Acid deposition control program

b. Cross State Air Pollution Rule

c. Mercury and Air Toxics Standards

d. Combustion turbine NESHAP rule

e. NAAQS

f. Regional Haze rule

g. Greenhouse gas regulations

h. 316(b) cooling water intake rule

i. Effluent Limitations Guidelines

j. Any new definition of waters of the United States

k. Coal Combustion Residuals rule

l. Pending enforcement actions by citizen groups or regulatory agencies of any state and/or federal environmental requirements.

A-27.
a. - l. See attached.

$ Millions

1 Capital

(a)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 0.9	$ 1.8	$ 0.4	$ 1.4	$ 2.1	$ 0.8	$ -	$ -	$ -	$ -	$ -
Ghent	$ 5.8	$ 3.6	$ 5.3	$ 10.0	$ 14.5	$ 9.9	$ 9.3	$ 11.4	$ 15.4	$ 3.7	$ 6.7
Mill Creek	$ 2.9	$ 0.6	$ 2.4	$ 2.0	$ 1.9	$ 5.6	$ 7.2	$ 4.3	$ 6.3	$ 3.9	$ 8.4
Trimble County	$ 4.6	$ 2.4	$ 2.0	$ 2.6	$ 3.3	$ 6.7	$ 7.7	$ 4.3	$ 10.0	$ 6.1	$ 7.0

(b)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 8.3	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ 0.0	$ -	$ -	$ -	$ -
Ghent	$ 46.2	$ 16.9	$ 16.4	$ 2.9	$ 0.7	$ 0.6	$ 1.0	$ 0.9	$ 4.7	$ 10.6	$ 2.6
Mill Creek	$ 9.6	$ 0.2	$ 0.2	$ 0.6	$ 1.0	$ 2.2	$ 2.5	$ 2.9	$ 0.5	$ 0.1	$ 0.3
Trimble County	$ 25.6	$ 22.0	$ 23.3	$ 17.3	$ 0.3	$ 0.3	$ 1.2	$ 2.0	$ 0.1	$ 0.1	$ 0.1

(c)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 0.1	$ 0.6	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ghent	$ 35.7	$ 57.2	$ 28.8	$ 3.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mill Creek	$ 15.3	$ 24.0	$ 10.0	$ 11.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trimble County	$ 12.0	$ 21.4	$ 6.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(d)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ghent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mill Creek	$ 0.4	$ 1.2	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trimble County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

(1) The 2021 expenses are actual costs incurred. The Company's official Business Plan is presented for the time period 2022 through 2026, with projections for an additional five years. The Company does not have estimated expenses past 2031.

(2) Capital expenses are not available by unit.

(3) Capital expenses apply to multiple regulations as follows:

- **(a)** Expenses included in (a) are to comply with the following: Acid Deposition Control Program, Cross State Air Pollution Rule, Mercury and Air Toxics Standards, NAAQS.
- **(b)** Expenses included in (b) are to comply with the Coal Combustion Residuals Rule.
- **(c)** Expenses included in (c) are to comply with the Effluent Limitation Guidelines and 316(b) Cooling Water Intake Rule.
- **(d)** Expenses included in (d) are to comply with the Regional Haze Rule.

(4) The Company has not incurred Capital expenses, and there are no expenses estimated, for the following: Combustion Turbine NESHAP rule, Greenhouse Gas regulations, Definition of Waters of the United States, or pending enforcement actions.

$ Millions

2 O&M

(a)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 3.5	$ 3.4	$ 3.4	$ 3.5	$ 3.5	$ 3.5	$ 3.3	$ -	$ -	$ -	$ -
Ghent	$ 20.1	$ 16.2	$ 17.5	$ 16.7	$ 17.0	$ 17.9	$ 17.7	$ 19.2	$ 19.0	$ 19.3	$ 19.8
Mill Creek	$ 14.7	$ 12.7	$ 13.1	$ 12.8	$ 12.9	$ 12.7	$ 12.6	$ 10.8	$ 10.9	$ 10.8	$ 11.2
Trimble County	$ 9.4	$ 7.3	$ 7.0	$ 7.3	$ 7.1	$ 7.1	$ 7.5	$ 8.0	$ 7.8	$ 7.9	$ 7.7

(b)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 3.0	$ 2.8	$ 2.9	$ 3.0	$ 3.2	$ 3.3	$ 3.4	$ -	$ -	$ -	$ -
Ghent	$ 9.7	$ 10.2	$ 11.5	$ 13.5	$ 13.5	$ 13.9	$ 14.9	$ 15.5	$ 15.8	$ 16.2	$ 15.8
Mill Creek	$ 3.9	$ 3.6	$ 3.6	$ 3.6	$ 3.8	$ 3.4	$ 3.5	$ 3.3	$ 3.3	$ 3.4	$ 3.5
Trimble County	$ 3.5	$ 4.6	$ 6.5	$ 6.8	$ 6.9	$ 7.1	$ 7.3	$ 7.6	$ 7.8	$ 8.0	$ 8.2

(c)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ghent	$ -	$ -	$ -	$ 2.6	$ 5.1	$ 5.1	$ 5.3	$ 5.4	$ 5.6	$ 5.7	$ 5.9
Mill Creek	$ -	$ -	$ -	$ 1.6	$ 3.4	$ 3.4	$ 2.1	$ 2.2	$ 2.2	$ 2.3	$ 2.3
Trimble County	$ -	$ -	$ 1.3	$ 2.7	$ 2.8	$ 2.9	$ 1.9	$ 2.0	$ 2.1	$ 2.1	$ 2.2

(d)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ghent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mill Creek	$ 1.6	$ 2.0	$ 2.0	$ 2.2	$ 2.3	$ 2.4	$ 2.6	$ 2.6	$ 2.6	$ 2.6	$ 2.7
Trimble County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

(e)	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
E.W. Brown	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Ghent	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Mill Creek	$ 0.3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Trimble County	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Notes:

(1) The 2021 expenses are actual costs incurred. The Company's official Business Plan is presented for the time period 2022 through 2026, with projections for an additional five years. The Company does not have estimated expenses past 2031.

(2) O&M expenses are not available by unit.

(3) O&M expenses apply to multiple regulations as follows:

- **(a)** Expenses included in (a) are to comply with the following: Acid Deposition Control Program, Cross State Air Pollution Rule, Mercury and Air Toxics Standards, NAAQS.
- **(b)** Expenses included in (b) are to comply with the Coal Combustion Residuals Rule.
- **(c)** Expenses included in (c) are to comply with the Effluent Limitation Guidelines.
- **(d)** Expenses included in (d) are to comply with the Regional Haze Rule.
- **(e)** Expenses included in (e) are for the E.W. Brown Herrington Lake Corrective Action Plan and the LG&E Mill Creek Generation Station Consent Decree (Civil Action No. 3:20-cv-00542-CRS)

(4) The Company has not incurred O&M expenses, and there are no expenses estimated, for the following: Combustion Turbine NESHAP rule, Greenhouse Gas regulations, 316(b) Cooling Water Intake rule, or Definition of Waters of the United States.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.28

Responding Witness: Stuart A. Wilson

Q-1.28. Please produce the energy market price forecasts and capacity market price forecasts used in the 2021 IRP Long-Term Resource Planning Analysis, along with supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

A-1.28. Not applicable. See the response to Question No. 9.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.29

Responding Witness: Stuart A. Wilson

Q-1.29. Please refer to the modeling conducted for the 2021 IRP Long-Term Resource Planning Analysis.

a. Please identify all constraints placed on the model's ability toselect or not select existing generating units, such as must-rundesignations or operational constraints.

b. For each of the Companies' coal-fired generating units and each modeling run, state whether the model was allowed to select retirement dates of existing coal-fired generating units, or whether the retirement dates for each coal unit were inputs into the modeling. For each unit for which the retirement date as an inputinto the modeling, explain how that retirement was determined.

c. Did the model evaluate dispatch of the Companies' generating units on an hourly, monthly, or annual basis?

d. Was the model limited in the amount of additional solar, wind, and battery resources it was allowed to select each year and/or cumulatively over 2021-2036? Please describe and provide the basis for any such constraints.

e. In developing the scenarios, did the Companies assume a relationship or correlation between any of the variables (load, natural gas prices, coal prices, and/or CO_2 prices)? If so, please identify the assumed correlations between each variable and provide supporting analyses, workpapers, and documentation (inmachine readable and unprotected format with formulas intact).

A-1.29.

a. The Companies' IRP modeling assumed that renewable PPAs, along with the minimum take portion of the Companies' contract with OVEC (typically about 50 MW of the Companies' share), generation from the Companies' solar facility at E.W. Brown, and generation from the Companies' hydro facilities at Ohio Falls were "must-run" for purposes of unit commitment and dispatch.

b. The analysis assumed fixed retirement dates as specified in Table 1 of the Long-Term Resource Planning Analysis in Vol. III of the IRP. As stated on page 3 of the Long-Term Resource Planning Analysis, Mill Creek 1 will be retired in 2024 as part of the Companies' least-cost plan for complying with the amended Effluent Limit Guidelines. Due to their age and inefficiency, the Companies' remaining small-frame SCCTs (Haefling 1-2 and Paddy's Run 12) are assumed to retire by 2025. Consistent with the analysis summarized in Case Nos. 2020-00349 and 2020-00350, Mill Creek 2 and Brown 3 are assumed to retire in 2028. The retirement year for each of the remaining units is the end of the unit's book depreciation life.

c. The Companies' modeling evaluated dispatch on an hourly basis.

d. No.

e. The Companies assumed that the level of coal prices was correlated with the level of gas prices, based on the historical relationship between changes in coal and gas prices, as discussed in Section 3.4.2 on page 13 of the "2021 IRP Long-Term Resource Planning Analysis" ("LTRPA") in IRP Volume III. See attachment being provided in Excel format. Certain information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The Companies did not assume a correlation between load and fuel prices, but instead evaluated all combinations of the low, base, and high scenarios for load and fuel prices, as explained in Sections 4.2 and 4.3 of the LTRPA.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.30

Responding Witness: John Bevington / Stuart A. Wilson

Q-1.30. Refer to the 2021 IRP Long-Term Resource Planning Analysis, Table 14. Please explain the basis for the Companies' assumption that no incremental reduction in peak load will be achieved through DSM programs between 2025 and 2036. Please provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

a. Compare the referenced Table 14 with Table 15 in the same document. Please explain in full the basis for the Companies' assumption that DSM programs (including demand response and energy efficiency) have no impact on the winter peak demand throughout the study period.

A-1.30. The impact of historical and current non-dispatchable DSM on summer peak demand is estimated through the end of 2025, the period for which the Companies have Commission approval to continue current programs, and then held constant. However, the IRP load forecasts were developed with the assumption that energy efficiency improvements from DSM and other customer actions would continue throughout the IRP analysis period. See section titled "Energy Efficiency" beginning on page 5-25 of Volume I. By 2036, energy efficiency improvements in the base forecast reduce residential and commercial sales by over 6 percent compared to a case where end-use efficiencies are assumed to remain unchanged. Also see the response to PSC 1-4a.

a. Non-dispatchable DSM programs have an impact on peak demand in the winter, but the Companies do not estimate the magnitude of this impact. The Companies' dispatchable DSM Programs ("Demand Conservation Program" or "DCP") primarily utilize control switches on customer AC units. Since AC units do not typically operate in the winter, initiating a program control event in the winter would have no impact on winter peak demand.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.31

Responding Witness: Stuart A. Wilson

Q-1.31. Please provide the results of, and any supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact) for, the Companies' January 7, 2021 RFP for 300 MW to 900 MW beginning in 2025 and no later than 2028.

a. Refer to the 2021 IRP Long-term Resource Planning Analysis. What steps, if any, did the Companies take to ensure that costs assumed in the 2021 IRP are consistent with the results of the RFP? Please explain your response in detail and provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact).

A-1.31. See the responses to SC 1-5 and PSC 1-56. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

a. See above and the responses to PSC 1-26 parts (a) and (g).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.32

Responding Witness: Stuart A. Wilson

Q-1.32. Please refer to the 2021 IRP Resource Screening Analysis. Did the Companies consider out-of-state wind, solar, and battery resources? If so, please indicate what out-of-state resources were considered and provide supporting analyses, workpapers, and documentation (in machine readable and unprotected format with formulas intact). If not, please state why not.

A-1.32. See the response to PSC 1-22 and PSC 1-42 part (d).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.33

Responding Witness: Stuart Wilson / Christopher D. Balmer

Q-1.33. Please refer to the 2021 RTO Membership analysis.

a. What analytical approach, e.g., modeling, spreadsheet analysis,etc. was used to conduct this study?

b. Provide all workbooks with formulas and links intact used toconduct this analysis.

c. Provide the documents that support the assumptions made regarding the costs and benefits of RTO membership including but not limited to uplift charges, lost transmission revenue, administrative fees, energy market benefits, capacity market benefits, etc.

d. How did the Companies' treat the impacts of changes in reserve margin requirements from joining an RTO?

A-1.33.

a. The methodology, key assumptions, cost components, benefit components, quantitative results, and long-term considerations are explained in Sections 5 – 10 of the *2021 RTO Membership Analysis*.

b. See the response to Question No. 3. The RTO Analysis documents are located in the "2021RTOAnalysis" folder.

c. See the response to part (b).

d. See Section 8.1.4 of the *2021 RTO Membership Analysis*.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.34

Responding Witness: David S. Sinclair

Q-1.34. Refer to the 2021 RTO Membership Analysis, page 13, stating, "The RTOs have seen very low capacity prices, much lower than the actual cost of new entry. This combined with the limited forward visibility of PJM's 3- year-ahead and MISO 1-year-ahead market leads to little incentive for the construction of new capacity, which could lead to capacity deficiencies if not addressed."

a. Please identify any examples of capacity deficiencies in PJM or MISO, as referred to in the above sentence, of which you are aware.

b. Have the Companies prepared or caused to be prepared any analysis of the capacity deficiency concerns described in subpart a? If so, please produce any such analyses and identify the portions of such analyses that support the above quoted sentence. If not, please explain in detail why not.

A-1.34.

a. See the responses to Question No. 35 and SREA 1-18(j). The North American Electric Reliability Corporation ("NERC") in its 2021 Long-Term Reliability Assessment projects the potential for a capacity shortfall in MISO as soon as 2024.[5]

b. The Companies have not performed this analysis. There is sufficient publicly available information to support the referenced statement. See the responses to part (a) and SREA 1-18(j).

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[5] "2021 Long-Term Reliability Assessment," NERC, December 2021, page 58. *See* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.35

Responding Witness: Charles R. Schram

Q-1.35. Refer to the 2021 RTO Membership Analysis, page 17, stating, "The Companies have identified eight EEA events experience within MISO since 2017." Please identify the eight EEA events and provide supporting documentation.

A-1.35. See attached. Since the October submission of the RTO Membership Analysis, the Companies discovered a ninth EEA event within MISO that is also included in the attachment.

Date	MISO Max Gen Event Step	Corresponding EEA Level	Evidence	Link
6/10/2021	2a	2	E-mail notification from MISO	N/A - E-mail only
2/16/2021	5	3	E-mail notification from MISO	N/A - E-mail only
8/27/2020	5	3	E-mail notification from MISO	N/A - E-mail only
5/16/2019	2a	2	MISO Presentation "MISO May South Region Operating Condition Review" Dated June 6, 2019. Slide 7 indicates "Max Gen Event 2a Declaration" which corresponds with declaration of NERC EEA 2 as shown on slide 15.	https://cdn.misoenergy.org/20190606%20MSC%20Item%2008%20May%2016%20Max%20Gen%20Review352708.pdf
1/30/2019	2a/b	2	MISO Presentation "MISO January 30-31 Maximum Generation Event Overview" Dated March 7, 2019. Slides 17 and 18 indicate the declaration of Max Gen Event Step 2a/b which corresponds with declaration of NERC EEA2 as shown on slide 19.	https://cdn.misoenergy.org/20190307%20MSC%20Item%2003%20Jan%2030%20Max%20Gen%20Event325263.pdf
9/15/2018	2c	2	MISO Presentation "MISO September 15 Maximum Generation Event Overview" Dated October 11, 2018. Slide 15 indicates the declaration of Max Gen Event Step 2 which corresponds with declaration of NERC EEA2 as shown on Slide 13.	https://cdn.misoenergy.org/20181011%20MSC%20Item%2003%20Max%20Gen%20Event282648.pdf
1/17/2018	2c	2	MISO Presentation "MISO January 17-18 Maximum Generation Event Overview" Dated February 8, 2018. Slide 17 indicates declaration of "EEA Level 2 and Maximum Generation Event - Step 2a/b".	https://cdn.misoenergy.org/20180208%20MSC%20Item%2008%20Update%20on%20January%20Weather%20and%20Winter%20Storm%20Inga122372.pdf
9/22/2017	1b/c	1	MISO Whitepaper "Resource Availability and Need" Dated March 30, 2018. Page 14 indicates declaration of Max Gen Event Step 1b/c which corresponds with declaration of NERC EEA1 as shown on page 15.	https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf
4/4/2017	2a/b	2	MISO Whitepaper "Resource Availability and Need" Dated March 30, 2018. Page 14 indicates declaration of Max Gen Event Step 2a/b which corresponds with declaration of NERC EEA2 as shown on page 15.	https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

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From:	Real-Time and Market Notifications MCS SuperList <MISORTMKTMCSSL@LISTS.MISOENERGY.ORG> on behalf of DoNotReplyMCS@misoenergy.org
Sent:	Thursday, June 10, 2021 1:05 PM
To:	MISORTMKTMCSSL@LISTS.MISOENERGY.ORG
Subject:	[MISO] Max Gen Event North and Central Regions - EEA 2 effective 06/10/2021 14:00 EST

EXTERNAL email. STOP and THINK before responding, clicking on links, or opening attachments.

Current NERC EEA Level = 2
Current MISO Max Gen Level = Event Step 2a
Current Emergency Pricing Level = Tier 2

Reliability Actions:

The MISO Reliability Coordinator is declaring a Maximum Generation Emergency Event Step 2a effective from 06/10/2021 14:00 EST until 06/10/2021 18:00 EST for the following entities: Central Region area(s) of: ALT, ALTE, AMIL, AMMO, AMRN, ATC, BREC, CIN, CONS, CWLD, CWLP, DECO, GLH, HE, HMPL, IPL, ITC, MECS, METC, MGE, MIUP, NIPS, PION, RTX, SIGE, SIPC, UPPC, WEC, WPS and North Region area(s) of: ALTW, DPC, GRE, ITCM, MDU, MEC, MP, MPW, NSP, OTP, SMP

The reason for the Event is because of Forced Generation Outages, Above Normal Temps, Higher than Forecasted Load.

The MISO Reliability Coordinator instructs the following:

Stakeholder Major Actions	**Max Gen Step Level**
As directed by MISO, LBAs reduce load via LMM - Stage 1	2a
As directed by MISO, MPs implement LMRs via MCS-LMR Tool	2a
MPs review Offers and ensure all available Emergency ranges and Resources are offered	1b
As directed by MISO, LBAs/GOPs/MPs start AME Resources	1a
MPs update EDR availability and MW amounts	Warning
LBAs update LMM availability via Load Management Form in the MCS	Warning
MPs ensure LMR availability data is correct in the MCS-LMR tool	Warning
MPs schedule available Module E Resources into the declaration area	Warning
As directed by MISO RC, TOPs implement reconfiguration options	Warning
MPs communicate available Module E Resources	Alert
MPs update energy interchange transaction E-Tags of Capacity Resources	Alert
LBA/TOP provide potential exclusion of constrained pockets within the declaration area	Alert
TOPs coordinate with MISO RC to identify potential reconfiguration options	Alert
LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS	Alert

Affected GOPs communicate capacity limited facilities to MISO and update limits and offers	Alert
Prepare to implement this procedure and follow procedures for emergency conditions	Capacity Advisory
Follow instructions per Conservative System Operations procedure and declaration	Capacity Advisory
If notified by MISO, Implement LMRs	Capacity Advisory

Please do not reply to this email. If you have any questions, please contact Client Relations at 1-866-296-6476, option 3. For technical support, choose option 1.

****
Created By User: Mike Dimascio

Sent to Groups: MISO Reliability LBA/TO, MISO OPC, MISO Shift Manager, All Market Participants, All MISO Employees,
Sent to Users: Mike Dimascio,

Do not reply to this message. If you have questions, please contact the Help Center.

MISO
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Find directions and contact information on our website.

From:	Real-Time and Market Notifications MCS SuperList <MISORTMKTMCSSL@LISTS.MISOENERGY.ORG> on behalf of DoNotReplyMCS@misoenergy.org
Sent:	Tuesday, February 16, 2021 9:58 PM
To:	MISORTMKTMCSSL@LISTS.MISOENERGY.ORG
Subject:	[MISO] Max Gen Event - EEA 2 effective 02/16/2021 22:00 EST

Current NERC EEA Level = 2
Current MISO Max Gen Level = Event Step 2a
Current Emergency Pricing Level = Tier 2

Reliability Actions:

The MISO Reliability Coordinator is declaring a Maximum Generation Emergency Event Step 2a effective from 02/16/2021 22:00 EST until 02/17/2021 01:00 EST for the following entities: South Region area(s) of: AXLT, CLEC, EAI, EES, EMBA, LAFA, LAGN, LEPA, SME

The reason for the Event is because of Forced Generation Outages.

The MISO Reliability Coordinator instructs the following:

Stakeholder Major Actions	**Max Gen Step Level**
As directed by MISO, LBAs reduce load via LMM - Stage 1	2a
As directed by MISO, MPs implement LMRs via MCS-LMR Tool	2a
MPs review Offers and ensure all available Emergency ranges and Resources are offered	1b
As directed by MISO, LBAs/GOPs/MPs start AME Resources	1a
MPs update EDR availability and MW amounts	Warning
LBAs update LMM availability via Load Management Form in the MCS	Warning
MPs ensure LMR availability data is correct in the MCS-LMR tool	Warning
MPs schedule available Module E Resources into the declaration area	Warning
As directed by MISO RC, TOPs implement reconfiguration options	Warning
MPs communicate available Module E Resources	Alert
MPs update energy interchange transaction E-Tags of Capacity Resources	Alert
LBA/TOP provide potential exclusion of constrained pockets within the declaration area	Alert
TOPs coordinate with MISO RC to identify potential reconfiguration options	Alert
LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS	Alert
Affected GOPs communicate capacity limited facilities to MISO and update limits and offers	Alert
Prepare to implement this procedure and follow procedures for emergency conditions	Capacity Advisory

Follow instructions per Conservative System Operations procedure and declaration	Capacity Advisory
If notified by MISO, Implement LMRs	Capacity Advisory

Please do not reply to this email. If you have any questions, please contact Client Relations at 1-866-296-6476, option 3. For technical support, choose option 1.

****

Created By User: Mike Dimascio

Sent to Groups: MISO Reliability LBA/TO, MISO OPC, MISO Shift Manager, All Market Participants, All MISO Employees,
Sent to Users: Mike Dimascio,

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MISO
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Find directions and contact information on our website.

From:	Real-Time and Market Notifications MCS SuperList <MISORTMKTMCSSL@LISTS.MISOENERGY.ORG> on behalf of DoNotReplyMCS@misoenergy.org
Sent:	Thursday, August 27, 2020 12:52 PM
To:	MISORTMKTMCSSL@LISTS.MISOENERGY.ORG
Subject:	[MISO] Max Gen Event - EEA 3 effective 08/27/2020 11:40 EST

Current NERC EEA Level = 3
Current MISO Max Gen Level = Event Step 5
Current Emergency Pricing Level = VOLL

Reliability Actions:

MISO is declaring a Maximum Generation Emergency Event Step 5 effective 11:40 EST until further notice for a portion of the MISO South Region. (The Western half of the WOTAB load pocket including all of the Western Load Pocket.

The reason for the Event is because of Forced Generation and Transmission Outages, and unpredictable load patterns due to Hurricane Laura.

The MISO Reliability Coordinator instructs the following:

Stakeholder Major Actions	**Max Gen Step Level**
LBAs shed load per MISO and confirm action via MCS Load Shed Tool	5
LBAs review OE-417 filing requirements	5
MPs continue to review Offers and ensure all available Emergency ranges and Resources are offered	4a
Affected LBAs reduce load via LMM - Stage 2	3b
Affected GOPs dispatch de-rated Generators with waivers from government regulations	3a
LBAs issue public appeals to reduce demand per internal procedures and OE-417 filings	2c
LBAs in declaration Event area shall prepare to shed Load.	2c
As directed by MISO, MPs commit EDRs	2b
As directed by MISO, LBAs reduce load via LMM - Stage 1	2a
As directed by MISO, MPs implement LMRs via MCS-LMR Tool	2a
MPs review Offers and ensure all available Emergency ranges and Resources are offered	1b
As directed by MISO, LBAs/GOPs/MPs start AME Resources	1a
MPs update EDR availability and MW amounts	Warning
LBAs update LMM availability via Load Management Form in the MCS	Warning

MPs ensure LMR availability data is correct in the MCS-LMR tool	Warning
MPs schedule available Module E Resources into the declaration area	Warning
As directed by MISO RC, TOPs implement reconfiguration options	Warning
MPs communicate available Module E Resources	Alert
MPs update energy interchange transaction E-Tags of Capacity Resources	Alert
LBA/TOP provide potential exclusion of constrained pockets within the declaration area	Alert
TOPs coordinate with MISO RC to identify potential reconfiguration options	Alert
LBAs/MPs ensure accuracy of LMM/LMR availability and Self Scheduled values in MCS	Alert
Affected GOPs communicate capacity limited facilities to MISO and update limits and offers	Alert
Prepare to implement this procedure and follow procedures for emergency conditions	Capacity Advisory
Follow instructions per Conservative System Operations procedure and declaration	Capacity Advisory
If notified by MISO, Implement LMRs	Capacity Advisory

Please do not reply to this email. If you have any questions, please contact Client Relations at 1-866-296-6476, option 3. For technical support, choose option 1.

****
Created By User: Christopher Hoffman

Sent to Groups: MISO Reliability LBA/TO, MISO OPC, MISO Shift Manager, All Market Participants, All MISO Employees,
Sent to Users: Christopher Hoffman,

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.36

Responding Witness: Stuart A. Wilson

Q-1.36. Please provide the Companies' average total annual electricity usage per residential customer.

A-1.36. See IRP, Volume I, page 7-6, Tables 7-15 and 7-16.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.37

Responding Witness: John Bevington

Q-1.37. Refer to Vol. I, section 8.(2).(b), addressing "New Demand-Side Management Programs."

a. Please identify each DSM-EE program evaluated for implementation during the planning period and provide the data and analysis used to evaluate each such DSM-EE program.

b. Have the Companies studied or caused to be studied the demand response and energy efficiency potential among their (i) residential customers or (ii) commercial customers since the March 2017 Residential and Commercial Potential Study prepared by Cadmus and submitted as Exhibit GSL-3 in Case No. 2017-00441? If so, please provide each such study.

c. Please provide the Companies' most recent study of demand response and energy efficiency potential among their industrial customers.

d. Please provide the most recent three full years of reported DSM-EE data (including program planned budgets and savings, actual spending and savings, and planned and actual participation) by program, in executable Excel format with formulae intact. Please also provide any energy efficiency or demand response Annual Reports prepared during this period.

e. Refer to Vol. I, Figure 5-9. Have the Companies considered winter demand response as a resource to address the variability in winter peak load? Please explain your response in detail.

A-1.37.

a. See the response to PSC 1-4.

b. See the attached document on the Demand Response Potential Study completed in 2021 by Cadmus, Inc.

c. See the response to part (b) for the Demand Response Potential Study.[6]

d. For planned/filed budgets, participants, and savings, please see pages 24 (starting at Table E), through 51 of 182 in Exhibit GSL-1, from Case No. 2017-00441. Note, since the School Energy Managers Program (SEMP)was disallowed, ignore the figures from Section 2.4.[7] For the requested actuals, see the attachment being provided in Excel format.

e. Yes, the Companies have begun to consider year-round demand-response options and will do an evaluation in preparation for the next major DSM Program Plan filing, which is currently expected to be filed sometime before the current programs expire on December 31, 2025.

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[6] The last industrial potential study can be found here: https://psc.ky.gov/pscecf/2014-00003/rick.lovekamp@lge-ku.com/05262016071923/Closed/LGE_KU_Ind_DSM_Potential_Study_2014-00003_05-26-16.pdf

[7] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf

Memorandum

To: John Hayden; Louisville Gas and Electric and Kentucky Utilities

From: Lakin Garth, Aquila Velonis, Dylan Harmon, Max Blasdel; Cadmus

Subject: 2023 LG&E and KU Demand Response Assessment

Date: April 1, 2021

Overview

For Louisville Gas and Electric and Kentucky Utilities (LG&E and KU), Cadmus performed the *2016 Industrial Sector DSM Potential Assessment* for 2016 to 2035 and the *2017 Demand-Side Management (DSM) Potential Study* for 2019 to 2038. These studies included estimates of demand response (DR) potential: The *2016 Industrial Sector DSM Potential Assessment* estimated DR potential for eligible industrial LG&E and KU customers only, and *the 2017 Demand-Side Management Potential Study* included DR potential for residential and commercial LG&E and KU customers.

LG&E and KU sought an update to the previously estimated DR potential for all customer sectors. In response to this request, Cadmus updated and combined the previous DR potential assessments for residential, commercial, and industrial LG&E and KU customers, making the following high-level updates:

- Utility information, including recent demand forecasts and customer eligibility requirements
- Program participation assumptions, demand reductions, and cost data for DR products
- Levelized costs and benefit/cost ratios for each DR product
- Estimates of winter DR potential for each sector and DR product
- Timeline for potential DR deployment over a 20-year period, beginning in 2023[1] and ending in 2042

This memo presents the results of an independent assessment of the market potential for electric DR products in the service territory of LG&E and KU over the 20-year planning horizon, from 2023 to 2042. The results of this assessment will help LG&E and KU identify cost-effective DR products and design future programs. In addition, this assessment will identify possible DR products to address LG&E and KU's projected capacity shortfall of 300 to 900 megawatts starting in 2025 through 2028.

This study builds upon previous assessments of DR in LG&E and KU's territory. It incorporates the latest baseline and DR data from primary and secondary sources and is informed by the work of other entities in the region and across the country.

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[1] 2023 aligns with LG&E and KU's planned program update.

Scope of Analysis and Approach

Data Collection

The DR potential study update used LG&E and KU's energy, demand, and customer data. After reviewing all data sources from the two previous potential studies, Cadmus assembled the following data from LG&E and KU: utility sales, forecast, and customer data, residential equipment saturation surveys, and economic assumptions and data including discount rates, line losses, and avoided capacity costs.

Demand Response Product Review

Prior to updating potential estimates, Cadmus compiled a comprehensive list of DR products currently available in the market. Cadmus defined each product and all the relative DR characteristics for each product. These characteristics included applicable sector or segment, controlled end use, approximate product cost, range of unit-level demand reduction, unit-level levelized cost range, DR requirements (e.g., advanced metering infrastructure [AMI] data required), product limitations, market acceptance, and potential competition with other products. **Error! Reference source not found.** lists the products Cadmus reviewed.

Based on the findings from the product review, Cadmus, LG&E, and KU screened and selected the most applicable DR products to model DR potential. As noted in **Error! Reference source not found.**, fourteen products were selected to conduct an in-depth analysis to assess the DR potential.

Table 1. Demand Response Reviewed and Selected Products

Product Class	Product Category	Product	Selected Products	Season	Sector
Direct Load Control (DLC)	Electric Vehicle (EV) DLC	EV Charger Control (Grid-Enabled)		Both	Residential
	Water Heat DLC	Electric Resistance Water Heat – Switch[a]	✓	Both	Residential
		Heat Pump Water Heat – Switch		Both	
		Electric Resistance Water Heat- Grid-Enabled	✓	Both	
		Heat Pump Water Heat - Grid-Enabled		Both	
	Pool Pump DLC	Pool Pump – Switch[a]	✓	Summer	Residential
	Heating and Cooling DLC	HVAC – Switch[a]	✓	Both	Residential or Commercial
		HVAC – Bring-Your-Own-Thermostat (BYOT)	✓	Both	
		HVAC – Direct Install Thermostat		Both	
	Demand Curtailment	AutoDR[a]	✓		Commercial and Industrial
		Manual		Both	
		Backup Generator (Gen) with AutoDR	✓	Both	Commercial and Industrial
	Irrigation DR	Irrigation Pump - Switch		Summer	Agriculture
Price-Based DR	Time of Use (TOU)	Participant-Driven	✓	Both	Residential
	Critical Peak Pricing (CPP)	Smart Thermostat or Participant-Driven	✓	Both	All
	Critical Peak Rebates (CPR)	Smart Thermostat or Participant-Driven	✓	Both	

Product Class	Product Category	Product	Selected Products	Season	Sector
	Demand Buyback	Bidding Platform		Both	Commercial and Industrial
	Interruptible Rates (Int. Rates)	Participant-Driven	✓	Both	
	Real-Time Pricing (RTP)	Participant-Driven	✓	Both	Industrial
Other	Behavioral DR	Real-time Customer Communication	✓	Both	Residential
	Battery Storage DR	Battery Storage - Grid-Enabled		Both	All
	Voltage Reduction	Demand Voltage Reduction (DVR)	✓	Both	All

[a] Programs currently offered by LG&E and KU

Demand Response Potential

For all the DR products selected from the DR product review, Cadmus modeled the DR potential and corresponding costs for the 20-year time frame beginning in 2023 and ending in 2042. As a starting point, Cadmus used existing models from *the 2016 Industrial Sector DSM Potential Assessment* for 2016 to 2035 and the *2017 Demand-Side Management Potential Study* for 2019 to 2038. We updated program participation assumptions, demand reductions, and cost data for each DR product with the recent data from our research and data collection where applicable.

Cadmus estimated both summer and winter DR potential for products that offer demand reduction opportunities in either season, as well as determined levelized costs and benefit/cost ratios for each DR product. We also performed a tipping point analysis for each product to determine the value at which the avoided generation capacity cost meets minimum cost-effectiveness criteria.

Summary of Results

Focusing on reducing a utility's capacity needs, DR programs rely on flexible loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. These programs seek to reduce peak demand and promote improved system reliability and may defer investments in delivery and generation infrastructure.

DR objectives may be met through a broad range of strategies, both price-based (such as time-of-use or interruptible rate) and incentive-based (such as DLC) strategies. This assessment considered 14 total DR product options[2] to estimate total market DR potential in LG&E and KU's service area during peak load. These product options included multiple residential and commercial DLC products targeting cooling, heating, and water heating end uses, commercial and industrial demand curtailment, and others. Cadmus reviewed recent DR literature, including evaluations of pilots and programs across the country, to design each DR program.

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[2] Cadmus assess 14 total products with several products having multiple design structures. For example, critical peak pricing products may include 'with enablement' or 'without enablement' (e.g., with and without smart thermostat control). As a result, 14 products totaling 18 product configurations were assessed for DR potential.

Summary of Market Potential

Cadmus ran four utility-season models to generate market potential results for LG&E and KU – one for each utility-season combination. Table and Table in the following sections present the summer and winter market potential for each modeled DR product in LG&E and KU's territory. The tables are specific to one of the product classes (DLC, curtailment, or price-based) and present market potential results for the first six years and the final year of this study. We modeled products that would require a new rate structure (most of the price-based products) to begin in 2024 to account for the additional time needed to submit a new rate case. We modeled all other products to begin in 2023.

Summer Potential

Cadmus modeled LG&E and KU's existing residential and small commercial DLC programs as well as a new BYOT product and a replacement heat pump/air conditioner (HP/AC) switch program.

Cadmus based the existing pool pump and water heating DLC product results on current participation counts and annual attritions—we did not model any new participants for these programs. Furthermore, we set these products to expire in 2028 in the model due to LG&E and KU's intention to pursue other options over these products.

The existing HP/AC DLC products (one-way and two-way)[3] have far more participants than the existing pool pump or water heat products, which is reflected in their much higher market potential. These modeled products are based on the assumption that all one-way and two-way HP/AC switches in LG&E and KU's inventory will be deployed in 2023. The market potential for the existing one-way HP/AC switches then declines 5% a year to reflect annual attrition.

The market potential for the existing two-way HP/AC switches, however, does not decline as quickly as the existing one-way HP/AC switches due to their greater reliability. The new HP/AC product mirrors the decline in existing one-way switches and demonstrates the scenario where LG&E and KU would replace all existing one-way HP/AC switches with two-way switches. This new HP/AC switch product also achieves the maximum market potential modeled—it achieves more market potential at full maturation (in 2042) than LG&E and KU's existing HP/AC DLC program.

Cadmus also modeled a BYOT product. This product targets customers with smart thermostats and pays participants an incentive to curtail load during events, similar to a switch DLC program. Table presents the market potential results for the various DLC products modeled.

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[3] One-way switch refers to one-way signal communication to activate during an event. Two-way switch provides send and receive signal communication during an event and can validate operation. As of 2020, LG&E and KU has roughly 160,000 one-way HP/AC switches deployed, 15,000 two-way HP/AC switches deployed, and 7,000 two-way HP/AC switches in storage.

Table 2. DLC Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Res DLC BYOT	0.2	0.2	0.9	2.8	5.5	9.2	44.4
Existing HP/AC DLC Program - One Way	62.0	58.8	55.5	52.2	49.0	45.7	0.0
Existing HP/AC DLC Program - Two Way	11.5	10.7	10.0	9.3	8.7	8.1	3.1
New HP/AC DLC Program	0.2	0.9	2.6	6.8	12.8	20.5	88.0
Existing Water Heat (WH) DLC Program	2.0	2.0	2.0	2.0	2.0	0.0	0.0
Existing Pool Pump DLC Program[a]	0.0	0.0	0.0	0.0	0.0	0.0	0.0

[a] The existing pool pump DLC program has very few participants making the market potential for the existing program a near-zero megawatt value.

Cadmus leveraged prior LG&E and KU implementation contract projections of the commercial curtailment program (2014) as well as from current megawatt commitments through the existing program (2020). Additionally, we modeled the curtailment programs with a $15 per kilowatt incentive that align with existing program offering. This incentive is low compared to similar programs across the country and an increased incentive could bring greater megawatt reductions. Similar programs have incentives ranging from $25 per kilowatt to $73 per kilowatt.[4] There is a ceiling to participation regardless of incentive based on customer energy needs limitations.

Cadmus conducted a price elasticity of demand analysis by varying incentives to assess the sensitivity of the potential demand reduction.[5] As the incentive increases from $15 to $30 per kilowatt, there could be an increase of potential by roughly 48%. Increasing the incentives $15 to $45 per kilowatt could see an increase by about 82% in the potential demand reduction.

Cadmus assessed the demand response curtailment potential for the industrial segment, which represents an eligibility expansion to LG&E and KU's existing curtailment program. While this analysis is based on system load shapes and customer segments, the actual ability of a customer to participate in a curtailment program is dependent on their business practices and the ability to interrupt or suspend operations. This is especially difficult to estimate for industrial customers because of the more unique situations of customers considering their industry and operating requirements.

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[4] Colorado Springs Utilities. Accessed 3/19/2021. "Peak Savings Program." https://www.csu.org/Pages/PeakSaving.aspx

CPS ENERGY. Accessed 3/19/2021. "Demand Response." https://cpsenergy.com/content/dam/corporate/en/Documents/EnergyEfficiency/DemandResponse.pdf

Eversource. Accessed 3/19/2021. "Demand Response." https://www.eversource.com/content/docs/default-source/save-money-energy/curtailment-demand-response.pdf?sfvrsn=8b3bc962_4

[5] The price elasticity value of 0.58 was used for this analysis according to the following: The Energy Journal. 2020. "Utility Customer Supply of Demand Response Capacity" by James Stewart.

The interruptible rates product includes both commercial and industrial customers and so it directly competes with the curtailment programs. It also would require extra steps to develop due to the need for a new rate case which would also need approval.

The modeled backup generator DR product suggested low potential in LG&E and KU's territory. This type of program can be difficult to estimate potential for as reliable data on existing generators is difficult to obtain. Cadmus assumed a portion of health care facilities, airports, and industrial facilities would have backup generation and that a subset would participate in the program. There are additional factors to consider when promoting backup generators, such as the cost of upgrading generators to comply with air quality regulations. Table 3 shows the additional potential for the existing commercial curtailment program and products.

Table 3. Curtailment Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Commercial Curtailment-AutoDR	23.5	25.6	27.6	29.6	31.5	33.4	33.3
Industrial Curtailment-AutoDR	0.0	0.6	2.3	4.6	9.1	13.6	22.4
C&I Curtailment-Backup Generator	0.0	0.2	0.7	1.5	2.2	2.9	7.1
C&I Interruptible Rates	0.0	1.6	6.2	12.4	24.7	36.9	59.5

Residential CPP and CPR are very similar in their effect, but are implemented differently by the utility. The biggest advantage of CPR over CPP for LG&E and KU is that a new rate case is not required. Moreover, CPR encourages load shifting during peak times via incentives, which motivates participation more than the residential behavioral DR product.

All modeled price-based programs require AMI deployment, which we incorporated into the modeling. AMI is used for evaluation, measurement, and verification (EM&V) for the price-based programs by comparing energy consumption during events to baseline averages for similar days. These customer baseline values may change overtime as data improve and vary by season.

The with enablement/no enablement distinction for the CPP/CPR products is related to how peak load shifting is achieved. With enablement products use smart thermostats to instigate a shift in a customer's load (though the customer can override this). No enablement products rely on customer's themselves to curtail their load during called events. While the ease and effectiveness of participation with enablement is greater, the eligibility for these programs is dependent on smart thermostat saturations. This suppresses their market potential in the early years of the programs. It should be noted that enablement could be achieved through other technologies, but smart thermostats are the most common technology used for residential programs.

Cadmus modeled DVR market potential using benchmarked data sources and documents found in LG&E and KU's most recent rate case, including the CVR potential study. It is important to note that CVR and DVR are mutually exclusive. Once CVR/DVR infrastructure is in place, the utility can decide to use it to prioritize peak load reduction or to limit energy consumption. In either case, the observed benefits of this new infrastructure will highly depend on the nature of the customers attached to the controlled substations as CVR and DVR's effectiveness varies by end use. Table 4 includes results for the price-based products, as well as DVR and residential behavioral DR.

Table 4. Pricing/Other Products - Summer Market Potential

Product	Summer Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
DVR	5.5	7.4	9.3	11.2	13.0	13.0	12.8
Industrial RTP	0.0	0.0	0.2	0.6	1.4	2.0	3.4
Residential Behavioral DR	0.0	0.2	0.5	1.1	1.9	2.5	3.3
Residential CPP-No Enablement	0.0	0.2	1.1	2.7	6.3	9.5	16.3
Residential CPP-With Enablement	0.0	0.1	0.4	1.1	3.0	5.1	24.2
Residential CPR-No Enablement	0.2	0.9	2.3	5.4	9.5	12.6	16.3
Residential CPR-With Enablement	0.0	0.2	0.8	2.2	4.5	6.8	24.2
Residential TOU	0.0	0.4	2.7	6.4	11.3	15.0	27.2

Winter potential

Cadmus modeled all DR products for both seasons, except for DLC pool pumps. The results reflect the seasonal shift in energy demand by end use and system shape. Winter potential is higher for most price-based products and industrial curtailment programs. This is primarily driven by a difference in seasonal end use shares.

Table displays the winter results for the modeled DLC products. Compared with the summer results, winter market potential values are lower for each HP/AC DLC product. This is primarily due to the difference in applicable equipment saturations. Nearly all LG&E and KU customers have electric AC units that can be curtailed during summer events, but less than half have electric heating units (air source heat pumps) that can be targeted for winter event curtailment.[6]

Table 5. DLC Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Residential DLC BYOT	0.1	0.1	0.3	0.9	1.7	2.8	13.7
Existing HP/AC DLC Program - One Way	13.4	12.7	11.9	11.2	10.5	9.8	0.0
Existing HP/AC DLC Program - Two Way	3.5	3.2	3.0	2.8	2.6	2.4	0.9
New HP/AC DLC Program	0.1	0.3	0.8	2.2	4.1	6.5	28.1
Existing WH DLC Program	2.0	2.0	2.0	2.0	2.0	0.0	0.0

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[6] Based on LG&E and KU's 2020 Heating and Cooling Source Appliance Survey.

Curtailment programs in the winter months saw slightly higher potential for programs that target industrial customers as indicated in Table .[7] While commercial potential is slightly less in the winter, it remains comparable to the summer months, making this a dependable year-round product.

Table 6. Curtailment Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
Commercial Curtailment-AutoDR	22.1	24.1	26.0	27.9	29.7	31.5	31.4
Industrial Curtailment-AutoDR	0.0	0.7	2.7	5.4	10.7	16.0	26.4
C&I Curtailment-Backup Generator	0.0	0.2	0.9	1.8	2.8	3.6	8.8
C&I Int. Rates	0.0	1.6	6.4	12.8	25.4	38.0	61.3

Table shows that all the price-based products and DVR and residential behavioral DR saw greater potential in the winter months compared with the summer months. This is demonstrative of the winter peak observed LG&E and KU annually.

Table 7. Pricing/Other Products - Winter Market Potential

Product	Winter Market Potential (MW)						
	2023	2024	2025	2026	2027	2028	2042
DVR	6.9	9.2	11.5	13.8	16.1	16.1	16.0
Industrial RTP	0.0	0.1	0.3	0.7	1.6	2.4	4.0
Residential Behavioral DR	0.1	0.3	0.7	1.8	3.1	4.1	5.3
Residential CPP-No Enablement	0.0	0.3	1.5	3.6	8.4	12.5	21.3
Residential CPP-With Enablement	0.0	0.1	0.5	1.4	3.9	6.6	30.8
Residential CPR-No Enablement	0.2	1.2	3.0	7.2	12.5	16.7	21.3
Residential CPR-With Enablement	0.0	0.3	1.0	2.9	5.8	8.8	30.8
Residential TOU	0.0	0.6	4.4	10.5	18.4	24.5	43.9

Summary of Program Costs

Table and Table summarize the modeled program costs by year for each DR product and each season. To assess cost-effectiveness of each season separately, we duplicated all program costs for each season.

Table 8. Summer Program Costs by Year

Product	Summer Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
DVR	$371	$104	$112	$121	$129	$65	$64
Industrial RTP	$300	$151	$152	$154	$159	$158	$150
Residential Behavioral DR	$152	$12	$30	$72	$126	$169	$218
Residential DLC BYOT	$168	$25	$96	$285	$565	$938	$4,537
Existing HP/AC DLC Program - One Way	$4,732	$4,483	$4,234	$3,985	$3,736	$3,487	$0

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[7] It is important to note that these results are for both utilities combined and the unique distribution of customer types, system shape, and other factors specific to each utility would affect the potential for each utility.

Product	Summer Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
Existing HP/AC DLC Program - Two Way	$651	$608	$567	$529	$494	$461	$177
New HP/AC DLC Program	$82	$273	$747	$1,893	$2,879	$4,010	$7,973
Existing WH DLC Program	$368	$367	$365	$364	$362	$0	$0
Existing Pool Pump DLC Program	$1	$1	$1	$1	$1	$0	$0
Residential CPP-No Enablement	$300	$178	$265	$357	$623	$588	$255
Residential CPP-With Enablement	$300	$154	$170	$195	$270	$290	$289
Residential CPR-No Enablement	$321	$247	$335	$583	$730	$652	$313
Residential CPR-With Enablement	$302	$165	$189	$257	$331	$359	$471
Residential TOU	$150	$66	$410	$675	$877	$706	$110
Commercial Curtailment-AutoDR	$730	$847	$884	$920	$956	$992	$944
Industrial Curtailment-AutoDR	$346	$244	$355	$453	$709	$843	$859
C&I Curtailment-Backup Generator	$347	$532	$1,212	$1,581	$1,630	$1,680	$780
C&I Int. Rates	$346	$244	$355	$453	$709	$843	$859

Table 9. Winter Program Costs by Year

Product	Winter Program Costs (thousand $)						
	2023	2024	2025	2026	2027	2028	2042
DVR	$424	$129	$139	$150	$161	$80	$80
Industrial RTP	$300	$151	$152	$154	$159	$158	$150
Residential Behavioral DR	$154	$20	$49	$118	$206	$275	$352
Residential DLC BYOT	$154	$6	$24	$70	$140	$232	$1,122
Existing HP/AC DLC Program - One Way	$1,107	$1,049	$991	$932	$874	$816	$0
Existing HP/AC DLC Program - Two Way	$152	$142	$133	$124	$116	$108	$41
New HP/AC DLC Program	$20	$68	$186	$471	$717	$998	$1,986
Existing WH DLC Program	$368	$367	$365	$364	$362	$0	$0
Residential CPP-No Enablement	$300	$178	$265	$357	$623	$588	$255
Residential CPP-With Enablement	$300	$154	$170	$195	$270	$290	$289
Residential CPR-No Enablement	$321	$251	$345	$607	$772	$709	$384
Residential CPR-With Enablement	$303	$168	$197	$282	$381	$435	$732
Residential TOU	$150	$66	$410	$675	$877	$706	$110
Commercial Curtailment-AutoDR	$770	$917	$958	$997	$1,038	$1,077	$1,012
Industrial Curtailment-AutoDR	$346	$245	$359	$462	$727	$870	$903
C&I Curtailment-Backup Generator	$347	$532	$1,212	$1,581	$1,630	$1,680	$780
C&I Int. Rates	$346	$245	$359	$462	$727	$870	$903

Cost-Effectiveness Results

Cadmus generated benefit/cost ratios for all modeled DR products to compare the cost-effectiveness of each product.[8] Costs include various program costs such as setup costs, marketing costs, equipment costs, O&M costs, incentive payments, and others. The benefits are defined as the avoided capacity cost

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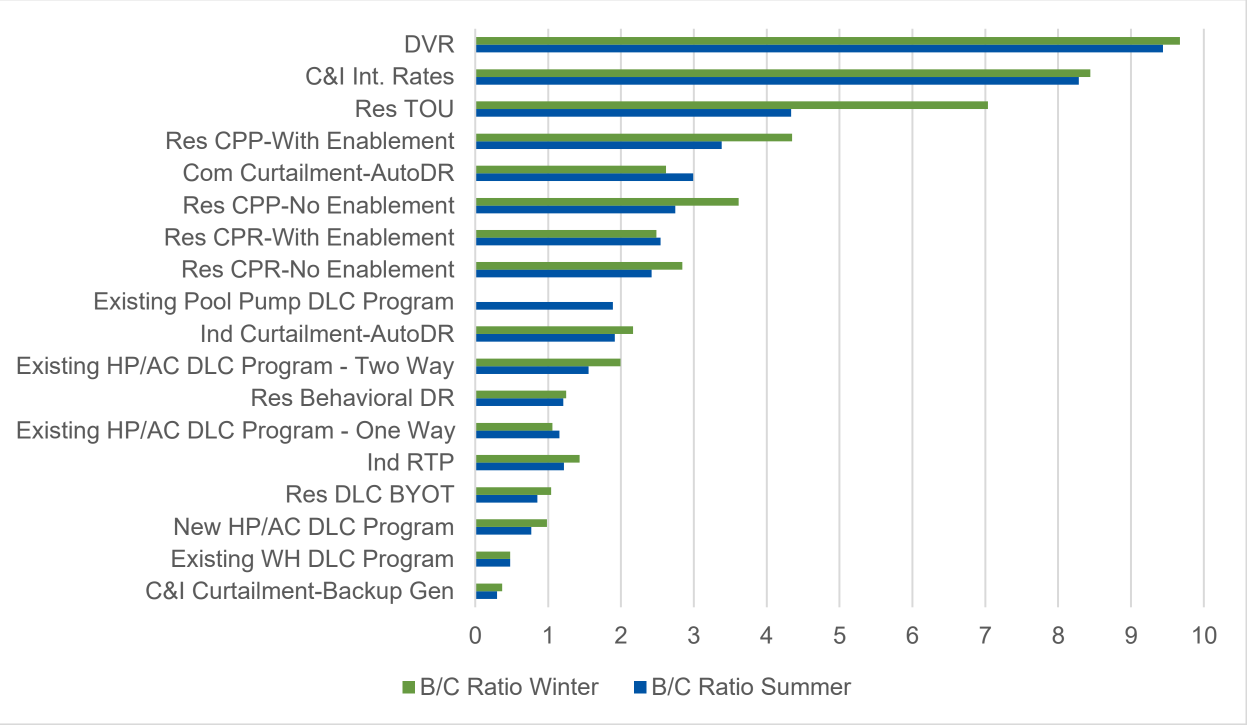
[8] The benefit/cost ratios following the Total Resource Cost (TRC) test methodology to assess product cost effectiveness. This follows a same approach as prior LG&E and KU demand response program cost effectiveness analysis as part of program planning.

and vary depending on the DR product start year and year of capacity need, identified as 2028. Cadmus used avoided capacity cost estimates provided by LG&E and KU for these calculations.[9] Figure 1 summarizes the benefit/cost ratio of each modeled DR product. All benefit/cost ratios above 1.0 are considered cost effective.

Figure 1. Cost-Effectiveness Results



Tipping Point Analysis Results

Cadmus also performed a tipping point analysis for each of the modeled DR products. This analysis determined the minimum threshold the avoided capacity cost (in $/kW-year) needs to be for each DR product to be cost-effective. Because the only benefit considered in this analysis is the avoided capacity cost, these tipping point costs are equivalent to the levelized cost for each product.

As previously mentioned, the avoided capacity cost varies by product start year. We assigned products that begin in 2023 an avoided capacity cost of $88 per kilowatt-year and those that began in 2024 an avoided capacity cost of $95 per kilowatt-year. Figure 2 summarizes the findings of the tipping point analysis. All products lower than avoided capacity cost threshold (red line), the product would still be cost effective with a lower avoided capacity cost. However, all products higher than red line would require higher avoided capacity cost to remain cost effective.

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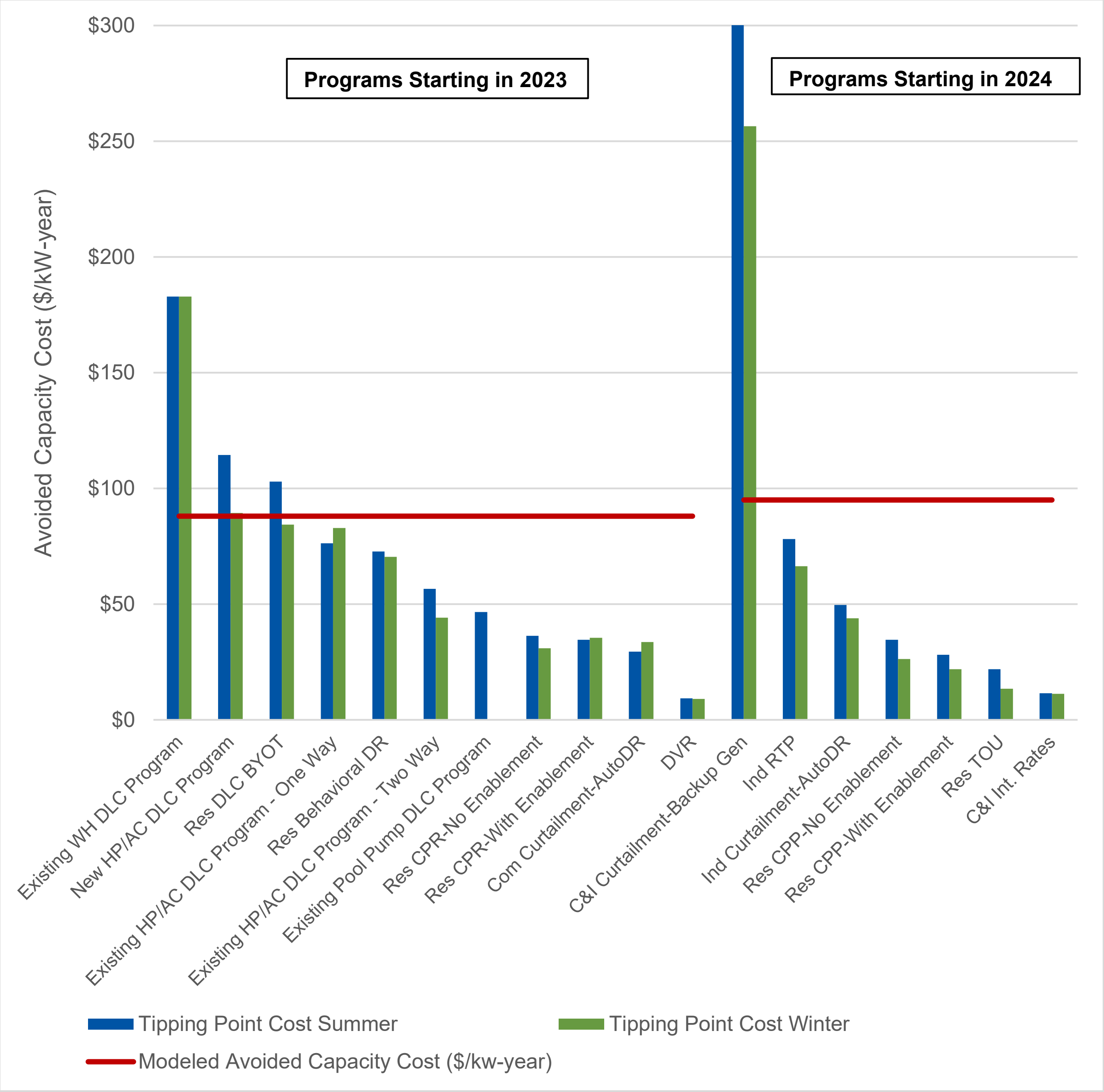
[9] LG&E and KU provided Cadmus with a draft document with estimated avoided capacity costs based on the year of capacity need and the year a newly dispatchable program is available.

Figure 2. Tipping Point Analysis Results



Recommendations

There are several key recommendations for LG&E and KU to consider based on the results of this analysis:

- ***Maintain Existing Residential and Small Commercial DLC Switch Program.*** Replacing all existing one-way switches with new two-way switches is not cost-effective. Existing one-way switches will continue to fail, customers will opt-out, etc. By 2028, existing DLC may decline from 66 MW (in 2017) to roughly 54 MW or less (depending on rate of failures and opt-outs). Cadmus recommends partial one-way replacement by expanding the number of two-switches from 22,000 to roughly 60,000 to slow the rate of attrition.
- ***Expand Existing Commercial Curtailment Program.*** The Curtailment program is highly cost-effective and has room to grow. Cadmus recommends expanding commercial customer base (actively recruit new commercial customers) and including industrial customers as eligible participants. Consider increasing incentives to promote the program—this would increase megawatt potential.
- ***Implement New Residential Critical Peak Rebates Program.*** CPR (unlike CPP) does not require a new rate structure and can be deployed quickly. CPR provides more megawatts than residential behavioral DR programs because CPR offers an incentive to participants. Because CPR with enablement requires smart thermostats, Cadmus recommends CPR without enablement to be implemented as it offers more flexibility and faster adoption. It is important to note, this product is reliant upon AMI deployment.
- ***Consider Residential Time of Use.*** This product offers high summer and winter megawatt potential. While it does compete with CPR, it would provide a companion program that gives customers different options. It is important to note, this product is reliant upon AMI deployment and would require a new rate structure.
- ***Evaluate Conservation Voltage Reduction for Demand Reduction.*** Potential for demand reduction as part of CVR is approximately 13 MW (summer) by 2027 if leveraged for demand reduction. Though the actual MW potential is highly dependent on substation customer base. LG&E and KU should either evaluate demand reduction potential from CVR or assess the feasibility of DVR instead of CVR to isolate substations (or control points) with a favorable mix of customer loads for higher demand potential.

Conclusions

LG&E and KU are anticipating a 300 MW to 900 MW capacity shortfall starting as early as 2025 through 2028. To address this shortfall, demand response can provide both short-term and long-term needs as a flexible load reduction resource. Existing LG&E and KU residential and small commercial DLC program have provided 66 megawatts (according to event data in 2017) and the large commercial curtailment program can provide 22 megawatts (according to 2020 customer commitments) of load reduction.

- Compared to LG&E and KU existing programs, the DR products recommended above meet approximately, an additional 21 MW by 2025 and 39 MW by 2028 could be added as a resource through these DR programs for summer peak. As shown in Table 10, in 2025, the total across all recommended products has a summer demand reduction of 109 megawatts. In 2028, the total summer demand reduction is 126.5 megawatts. Cadmus estimated the total levelized costs to be $48.6 per kilowatt-year for the summer peak.

Table 10. Total Demand Reduction of Recommended Products

Product	Summer MW (2025)	Winter MW (2025)	Summer MW (2028)	Winter MW (2028)	Summer Levelized Cost ($/kW-Year)	Winter Levelized Cost ($/kW-Year)
Existing DLC Program	67.5	17.0	53.9	12.3	74.9	82.0
Com Curtailment-AutoDR	27.6	26.0	33.4	31.5	29.4	33.6
Ind Curtailment-AutoDR	2.3	2.7	13.6	16.0	49.6	43.9
Res CPR-No Enablement	2.3	3.0	12.6	16.7	36.4	31.0
DVR	9.3	11.5	13.0	16.1	9.3	9.1
Total	**109.0**	**60.2**	**126.5**	**92.6**	**48.6**	**37.4**

- Commercial curtailment’s low levelized cost (tipping point cost) relative to the projected avoided capacity cost suggests additional market, incentives, and program funds could be leveraged to promote and expand this existing program.
    - Cadmus estimated, through a price elasticity of demand analysis, that increasing incentives from $15 to $30 per kilowatt, there could be an increase potential by roughly 48%. This translates to an additional 14.4 megawatts in 2025 and 22.6 megawatts in 2028 or combine across all recommended products totaling 123.4 megawatts and 149.1 megawatts, respectively.
    - Increasing incentives from $15 to $45 per kilowatt could see an increase by about 82% in demand reduction potential. This results in an additional 24.5 megawatts in 2025 and 38.5 megawatts in 2028 or combine across all recommended products totaling 133.5 megawatts and 165.0 megawatts, respectively.
- While the current commercial curtailment program is voluntary (customers can op-out during events), there are program design strategies to make this resource less flexible and more of a firm resource. The following represent a few possible strategies.
    - Set the program target of customer commitments higher than firm resource need.
    - Set customer fee penalties or remove customers who repeatably fail to meet their commitments. However, setting significant penalties may also have adverse effect on program participation.
    - Continue to educate customers about the benefits of demand response and actively promote event participation (LG&E and KU already does this within the current program).

To support LG&E and KU generation planning, Cadmus summarized the demand side management (DSM) megawatt reduction estimate achieved through demand response programs and products. In Table 11, the recommended products (DLC, curtailment, CPR, and DVR/CVR) provide the incremental megawatts (in addition to the demand reduction from existing programs). Cadmus applied a ten percent risk factor to avoid overestimating savings of program achievements and other unforeseen barriers (e.g., customer acceptance). The incremental megawatts from DR could provide generation planning, as a demand response resource, 32 megawatts in 2025 (summer) and 55 megawatts in 2028 (summer). In the event LG&E and KU's pending rate case does not receive approval for AMI deployment, this will limit the number of DR products that can be offered. As result, the non-AMI required DLC and curtailment AutoDR products could provide generation planning 21 megawatts in 2025 (summer) and 32 megawatts in 2028 (summer). The total levelized cost value for planning is $48.6 per kilowatt-year (2023 dollars)[10] for both summer and winter (conservative estimate for both seasons).

Table 11. Demand Response Potential Estimate

Demand Response Potential	Summer MW (2025)	Summer MW (2028)
Total Recommended Existing and New Programs (MW)	109.0	126.5
Incremental MW (Net existing programs ~ 88MW)	21.0	38.5
Additional MW with Higher AutoDR Incentives	14.4	22.6
Total Incremental MW	**35.4**	**61.1**
Program Risk Factor	10%	10%
Incremental MW DSM DR Estimate with AMI for Generation Planning (Rounded)	**32.0**	**55.0**
Incremental MW without AMI Generation Planning (Rounded)	**21.0**	**32.0**

Memorandum Addendum

Upon completion of this project, LG&E and KU became aware the residential and small commercial DLC two-way cellular devices installed with 3G service will no longer be maintained by the communication service provider as of December 31st, 2022. This effectively removes 21,000 two-way switches from the DLC program as well as removes 10.0 megawatts (2025) and 8.1 megawatts (2028) from the analysis conducted within this study. Cadmus suggests two options to mitigate the reduction in potential. First, consider replacing the obsolete equipment with new compatible communication devices. To ensure near-term viability of the DLC program, ongoing maintenance will be required to avoid more loses in demand response potential. Second, consider offering the commercial and industrial curtailment program options high incentives (e.g., $45 per kW) to increase program participation. As indicated within this study, increasing incentives from $30 per kW to $45 per kW could increase potential by 10.1 megawatts (2025) and 15.9 megawatts (2028), thereby offsetting the DLC program losses. In any planning estimate, there remains uncertainty in customer's awareness and willingness to participate in demand response programs that may impact the demand response achieved.

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[10] Timeline for potential DR deployment over a 20-year period, beginning in 2023.

Appendix A. Overview of Technical and Market Potential

Cadmus' analysis focused on programs aimed at reducing LG&E and KU's winter and summer peak demands. These programs include DLC space heat & cooling, DLC water heat, DLC pool pumps, nonresidential load curtailment, nonresidential backup generation, residential TOU, CPP, and CPR pricing, nonresidential interruptible rates, nonresidential RTP, and DVR. For these products, Cadmus provided options for all major customer segments and end uses in LG&E and KU's service territory.

We defined each DR program and its associated product option(s) according to typical program offerings, with specifications such as program implementation methods, applicable segments, affected end uses, load-reduction strategies, and incentives. To design the programs, we conducted an extensive review of secondary sources that addressed existing and planned programs throughout the country, such as DR potential assessments, program descriptions, evaluation reports, and pilot and demonstration projects from other utilities.

Estimate Technical Potential

Technical potential assumes 100% participation of eligible customers in all programs included in the assessment. Hence, technical potential represents a theoretical limit for unconstrained potential. Depending on the type of DR product, this study applies either a bottom-up or a top-down method to estimate technical potential.

This study uses the bottom-up method for assessing potential for DR programs that affect a piece of equipment in a specific end use, such as residential DLC space heat, residential DLC space cooling, and residential DLC water heat. In the bottom-up method, we determined technical potential as the product of three variables: number of eligible customers, equipment saturation rate, and the expected per-unit (kilowatt) peak load impact.

The top-down method estimates technical potential as a fraction of the participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use then estimates technical potential as a fraction of the end-use loads. We then estimated total potential by aggregating the estimated load reductions of the applicable end uses. We applied the top-down estimation method to DR products that target the entire facility or load (rather than specific equipment), such as commercial and industrial demand curtailment.

Estimate Market Potential

Market potential reflects a subset of technically feasible DR opportunities we assumed to be reasonably obtainable, based on market conditions and the end-use customers' ability and willingness to participate in the DR market. There are two components for estimating market potential: market acceptance (or the participation rate) and the ramp rate. We also broke down the participation rate into program participation (the likelihood of the eligible population to enroll in a DR program) and event participation (the probability that customers participating in a program will respond to a DR event), an important consideration in voluntary DR programs.

Ramp rates reflect the time needed for product design, planning, and deployment. Ramp rates vary depending on the type of DR product and the stage in the product's life cycle. We included LG&E and KU's projected AMI deployment in the ramp rate calculation for price-based measures that require AMI for EM&V. Ramp rates indicate when the maximum market potential may be reached, but they do not affect the amount of maximum market potential.

Both top-down and bottom-up methods calculate market potential as the product of peak load impact, program participation, and event participation. Both methods apply ramp rates in the same manner to account for program start-up and ramp-up.

Calculate Levelized Costs

In the context of demand response, levelized cost of electricity (LCOE) represents the constant per-kilowatt-year cost of deploying and operating a DR product, calculated as follows:

LCOE = (Annualized Cost of Demand Response Product) / (Achievable Annual Kilowatt Load Reduction)

For this assessment, Cadmus calculated levelized costs based on the total resource cost (TRC) perspective, which includes all known and quantifiable costs related to DR products and programs. The calculation of each DR product's levelized cost accounts for the relevant, direct costs of a DR product, including setup costs, program operation and maintenance costs, equipment cost, marketing cost, incentives, and transmission and distribution (T&D) deferral costs:

- **Upfront setup cost.** This cost item includes LG&E and KU's program development and setup costs for delivery of the subject DR products, prior to program implementation. We split these costs between the two utilities. Because upfront costs tend to be small relative to total program expenditures, they can be expected to have a small effect on levelized costs.
- **Program operations and maintenance (O&M) cost.** This cost item includes all expenses that LG&E and KU incurs annually to operate and maintain the program. Expenses may cover administration, event dispatching, customer engagement, infrastructure maintenance, managing opt-outs and new recruiting of loads, and evaluation.
- **Equipment cost (labor, material, and communication costs).** This cost item includes all expenses necessary to enable DR technology for each participating end user. The cost item applies only to each year's new participants. For some programs that assume or require end users to already have DR technology in place, this cost item would be zero.
- **Marketing cost.** This cost item includes all expenses for recruiting end users' participation in the program and applies only to new participants each year. For some programs (typically those run by third-party aggregators), the program O&M cost already includes this cost item.
- **Incremental Cost.** This cost item covers 75% of the incentives offered to end users each year. Incentives may take the form of fixed monthly or seasonal bill credits or may be variable, tied to actual kilowatt load reduction. This assessment included 75% of the assumed incentive payment to eligible participants in the TRC levelized-cost calculation. This approach follows the protocols established by the California Public Utilities Commission for assessing the cost effectiveness of

demand response products. Value for demand response is measured differently than energy efficiency programs for cost effectiveness tests.[2]

- **T&D costs.** Cadmus did not use a T&D value in the levelized cost calculations for each product.
- **Discount rate.** Cadmus used a 6.8% discount rate, consistent with LG&E and KU's resource planning assumptions, for all DR products.
- **Product life cycle.** We assessed all DR products with an assumed 20-year life cycle.[11]
- **Line Loss.** We used line loss values of 5.8% and 6.2% for LG&E and KU, respectively, to calculate demand savings at generation and affect total product benefits.

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[11] California Public Utilities Commission 2016 Demand Response Cost-Effectiveness Protocols.

Appendix B. Product Input Assumptions

The tables below summarize the modeling input assumptions Cadmus used for each DR product to generate the potential demand reduction results discussed in the main body of this memo.

Table B-1. Demand Voltage Reduction Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 full-time employee (FTE; split between utilities).
O&M Cost	$ per kW pledged per year	$5	Based on the Northwest Power and Conservation Council's 2021 Plan Bonneville Power Administration (BPA) Workbooks.
Equipment Cost	$ per new kW pledged	$35	
Marketing Cost	$ per new kW pledged	$0	
Incentives (annual)	$ per kW pledged per year	$0	
Incentives (one time)	$ per new kW pledged	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment/end-use load	Industrial: 15% Residential and Commercial: 85%	
Peak Load Impact	% of eligible segment/end-use load	0.47%	Based on LG&E and KU rate case Exhibit LEB-3. Appendix D, Page 2 of 10. Conservative scenario CVR system load reduction estimates a 0.47% load reduction.
Program Participation	% of eligible segment/end-use load	100%	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Event Participation	%	97%	
Ramp Rate	Number of years to reach maximum achievable potential	5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-2. Commercial Curtailment AutoDR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per year	$338,000	Based on the LG&E and KU Services Company Contract 2014 (split between utilities) and the Portfolio Performance Fee from the current contract 143095.
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.

Parameters	Units	Values	Notes
Marketing Cost	$ per participant per year	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per kW pledged per year	$15	Based on LG&E and KU website: https://lge-ku.com/business/demand-conservation-large
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of end-use load	KU: 51.7%; LGE: 59.0%	Based on non-residential customer billing database provided by LG&E and KU. Cadmus included only customers with an average annual demand greater than 200 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible segment/end-use load	30%	Based on Colorado Springs (Cadmus 2016): 30%; Black Hills Energy (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study.
Program Participation	% of eligible end-use load	KU: 11.3%; LGE: 12.6%	Based on customer load of current LG&E and KU curtailment program as a percentage of eligible load.
Event Participation	%	95%	Based on conversation with Enel X representative citing average observed event participation.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on current program impact and past contracted maximum curtailment MW values.

Table B-3. Industrial Curtailment AutoDR Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$196,000	Large Commercial DLC amendment to contract 143095 DR Service & Subscription Fee (split between utilities).
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.
Marketing Cost	$ per participant per year	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per kW pledged per year	$15	Based on LG&E and KU website: https://lge-ku.com/business/demand-conservation-large
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.

Parameters	Units	Values	Notes
Eligibility	% of end-use load	KU: 92.6%; LGE: 88.4%;	Based on non-residential customer billing database provided by LG&E and KU. Cadmus vetted customers with an average annual demand greater than 200 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible end-use load	30%	Colorado Springs (Cadmus 2016): 30%; Black Hills Energy (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study
Program Participation	% of eligible end-use load	KU: 8.3%; LGE: 9.2%	Determined using current program participants compared to all commercial customers.
Event Participation	% (switch success rate)	95%	Based on conversation with Enel X representative citing average observed event participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU planning files.

Table B-4. C&I Curtailment Backup Generator Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$196,000	Large Commercial DLC amendment to contract 143095 DR Service & Subscription Fee (split between utilities).
Equipment Cost	$ per new participant	$3,250	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Enablement Fee.
Marketing Cost	$ per new participant	$940	Enel X Large Commercial DLC Amendment to contract 143095 DR Site Management Fee.
Incentives (annual)	$ per participant per year	$5	Enel X Large Commercial DLC Amendment to contract 143095 Portfolio Performance Fee.
Incentives (one time)	$ per year	$800	Additional O&M incentive based on LBNL study of generator costs.
Attrition	% of existing participants per year	5%	Assume same as curtailment.
Eligibility	% of end-use load	Varies by Segment	Based on customer load database provided by LG&E and KU. Cadmus vetted customers with an average annual demand greater than 250 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible end-use load	KU: 17.1%; LGE: 2%	Calculated as 1/4 of peak qualifying customers.
Program Participation	% of eligible end-use load	KU: 3.3%; LGE: 3.6%	Considers likelihood to have generator based on segment and sector.
Event Participation	% (switch success rate)	95%	Based on PGE backup generator program.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	12	Assume slower ramp than AutoDR as customers may need to upgrade generators.

Table B-5. C&I Interruptible Rates Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$250,000	Based on the average value from Interstate Power and Light Company 2019-2023 Energy Efficiency Plan (Docket No. EEP-2018-0003)
Equipment Cost	$ per new participant	$0	No equipment costs required to participate.
Marketing Cost	$ per new participant	$25	Assumed based other similar programs.
Incentives (annual)	$ per kW pledged per year	$5.37[a]	Value from Interstate Power and Light Company 2019-2023 Energy Efficiency Plan (Docket No. EEP-2018-0003)[a]
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assume same as curtailment.
Eligibility	% of segment load	KU: 81.3%; LGE: 85.1%;	Based on customer load database provided by LG&E and KU. Cadmus vetted customers with a maximum demand greater than 250 kW to determine an eligible load percentage.
Peak Load Impact	% of eligible segment load	30%	Colorado Springs (Cadmus 2016): 30%; BHE (Applied 2018): 27% from the Black Hills/Colorado 2018 Electric DSM Baseline and Potential Study
Program Participation	% of eligible segment load	KU: 8.3%; LGE: 9.2%;	Same value as AutoDR.
Event Participation	n/a	99%	Assumed based on high penalties for non-participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Standard new product ramp up.

[a] Interstate Power and Light requires customers to commit to a minimum 200 kW reduction and achieve the contracted kilowatt reduction amount qualify for an interruptible credit. If customers fail to respond to an event, a one-time financial penalty of $36.50 per kilowatt for each excess kilowatt over their firm contract demand is levied.

Table B-6. Industrial RTP Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$0	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Equipment Cost	$ per new participant	$200	
Marketing Cost	$ per new participant	$0	
Incentives (annual)	n/a	$0	
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	0%	
Eligibility	% of segment load	100%	AMI dependency captured in ramp rate - eligibility value set to 100%.
Peak Load Impact	% of eligible segment load	Summer: 8% Winter: 4%	Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks.
Program Participation	% of eligible segment load	4%	
Event Participation	n/a	100%	
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350, standard product roll out ramp rate, and additional time to establish a new rate class.

Table B-7. Residential DLC BYOT Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per participant per year	$34	Based on a similar western utility pilot Wi-Fi program's costs, and consistent with Energy Hub estimates for software, licensing and DMRS setup of $25 - $35. And marketing based on research ranging from $10-$94 per new customer depending upon program: Consolidate Edison Cool NY pilot $10 and DLC Thermostats 3% total program costs; TVA 2011 potential study $50.
Equipment Cost	$ per new participant	$0	BYOT requires participants already have a smart thermostat.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.

Parameters	Units	Values	Notes
Incentives (annual)	$ per participant per year	$20	Benchmarked thermostat incentives include: PG&E $25; Xcel CO $50 towards purchase $5 per event participated; Austin Energy BYOD $85; Con Ed $25. Incentives for DLC switches include: PSE's pilot $50 for (space heat and water heat); Consolidate Edison Room A/C $10; Consolidated Edison ResSmart $25; Entergy $25 yearly for 50% cycle / $40 and $40 for 100% cycle; TVA potential study $55; ESource benchmarking monthly bill credits range from $5 to $32. Consolidated Edison BYOT incentive for $85 enrollment + $25 additional rebate (ESource); Orange & Rockland BYOT incentive for $85 enrollment + $25 for participation the following summer (ESource).
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Research shows a range from 2% to 9%. MRES 1%; Western Utility 1.5% (2015 Cadmus CPA); Rocky Mountain Power (2010) 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison evaluation 3.8% (2012); Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 95% Winter: 23%	Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Summer eligibility based on percent of questionnaire respondents who reported having an air conditioner in their home. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.6 Winter: 0.75	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.
Event Participation	% (switch success rate)	75%	CSU pilot in 2005 shows that 8.5% opt out at least 1 hour (Rocky Mountain Institute report); NV Energy 10% -13% non-responsive devices (NRD) including opt-out; CA Statewide report (1990s) 20% NRD during peak; Excel Co 54% of tech impact when including opt-out and off-line equipment (Wi-Fi); SDGE 56% overall with 22% opt-out, 8% signal failure, 17% equipment not in use during event.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	31	Cadmus conservatively estimated 10% smart thermostat saturation in 2023 and 3.3% annual growth in saturation. To inform this, Cadmus relied on data from the Northwest Residential Building Stock Assessment, Wisconsin Focus, and NYSERDA baseline studies. LG&E and KU currently does not offer incentives for smart thermostats, therefore Cadmus assumed smart thermostats saturations conservatively.

Table B-8. Residential HP/AC DLC Existing One-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assumption based on expectation that LG&E and KU's current one-way DLC switches will be phased out in the future.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.42 Winter: 0.75	Summer: Based on LG&E and KU 2017 SCRAM. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.

Parameters	Units	Values	Notes
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 50%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-9. Residential HP/AC DLC Existing Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 7.3%, KU: 6%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.

Parameters	Units	Values	Notes
Peak Load Impact	kW per participant (at meter)	Summer: 0.59 Winter: 0.75	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-10. Residential HP/AC DLC New Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$174	Based on discussion with LG&E and KU staff: new switches cost between $100 and $120 with an additional $64 for labor.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$25	Estimated based on MRES (2014) average of $22/customer, Duke Energy Carolina (2015) $32/customer, Duke Energy Ohio and Indiana (2015) $32-67/customer, PSO (2014) $25/CAC + $10/WH, OG&E (2014) same as PSO, and PacifiCorp (2013) $20/CAC + $10/WH.
Attrition	% of existing participants per year	5%	MRES 1% (2014); and PacifiCorp 7% (2012). Thermostat DLC program research ranges from 2% to 9%. CSU assumed 1.5% (2015); MRES 1%; Rocky Mountain Power 2010 had 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison 2012 program evaluation had 3.8%; Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 95% Winter: 23%	Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Summer eligibility based on percent of questionnaire respondents who reported having an air conditioner in their home. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home.
Peak Load Impact	kW per participant (at meter)	Summer: 0.59 Winter: 0.75	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Benchmarking included: SF 0.62 kW and MF 0.47 kW Xcel (2015), MRES (2014) 1.0 kW, Duke Energy Indiana (2015) 1.0-1.5 kW, Duke Energy Ohio (2015) 0.9-1.8 kW, and Duke Energy Carolinas 1.19-1.57 kW. PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH. The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	20%	Navigant (2012), Applied (2017), and Brattle (2016) use 20%. Global (2011) gives low- and high-range of 15% - 25%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	20	Mirrors the 20-year decline of the existing DLC products.

Table B-11.Residential DLC Electric Resistance Water Heater Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 0.5%, KU: 0.4%	Based on observed decline in DLC switch counts from 2017 to 2020.

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current water heat switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	0.35	PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-12. Residential DLC Pool Pump Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$30	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/demand-conservation
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 6%, KU: 0%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current pool pump switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	1.36	The California Codes and Standards commission found a range of 1.1 - 2.3 kW demand per pool pump. SDG&E (2013) found an average demand reduction of 1.91 kW, while SCE (2008) saw 1.36 kW reduction.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-13. Small Commercial HP/AC DLC Existing One-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assumption based on expectation that LG&E and KU's current one way DLC switches will be phased out in the future.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home. Residential data was used as a commercial proxy.
Peak Load Impact	kW per participant (at meter)	Summer: 0.42 Winter: 1.9	Summer: Based on LG&E and KU 2017 SCRAM. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 50%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-14. Small Commercial HP/AC DLC Existing Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative

Parameters	Units	Values	Notes
			costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 7.3%, KU: 6%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	Summer: 100% Winter: 23%	Summer: Customer count was manually adjusted to reflect current HP/AC switch counts - eligibility for this adjusted customer count is 100%. Winter: Based on LG&E and KU 2020 Heating and Cooling Source Appliance Questionnaire. Winter eligibility based on percent of questionnaire respondents who reported using a heat pump as the primary source of heating for their home. Residential data was used as a commercial proxy.
Peak Load Impact	kW per participant (at meter)	Summer: 1.1 Winter: 1.9	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	Summer: 100% Winter: 94%	Summer: Event participation accounted for kW impact SCRAM results - SCRAM kW impact represented [system kW reduction observed]/[count of all distributed switches (regardless of participation)]. Winter: SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year.

Table B-15. Small Commercial HP/AC DLC New Two-Way Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative

Parameters	Units	Values	Notes
			costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$174	Based on discussion with LG&E and KU staff: new switches cost between $100 and $120 with an additional $64 for labor.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$25	Estimated based on MRES (2014) average of $22/customer, Duke Energy Carolina (2015) $32/customer, Duke Energy Ohio and Indiana (2015) $32-67/customer, PSO (2014) $25/CAC + $10/WH, OG&E (2014) same as PSO, and PacifiCorp (2013) $20/CAC + $10/WH.
Attrition	% of existing participants per year	5%	MRES 1% (2014); and PacifiCorp 7% (2012). Thermostat DLC program research ranges from 2% to 9%. CSU assumed 1.5% (2015); MRES 1%; Rocky Mountain Power 2010 had 2%; IPL's 2014-18 plan assumes 3% attrition; Con Edison 2012 program evaluation had 3.8%; Avista thermostat pilot 4%; BPA Kootenai 5% (pilot), Xcel CO thermostat pilot 9% (2013).
Eligibility	% of customer count (e.g. equipment saturation)	30%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Peak Load Impact	kW per participant (at meter)	Summer: 1.1 Winter: 1.9	Summer: Based on the Northwest Power and Conservation Council's 2021 Plan BPA Workbooks. Winter: Applied (2017) for WA for small and medium C&I (3.72 kW), adjusted to small C&I (1.87 kW) using a ratio of HVAC capacity sizes between small and medium C&I facilities.
Program Participation	% of eligible customers	10%	Applied (2017): 2.3% - 3.4%; Global (2011): 10%; Brattle (2016): 14%; Navigant (2015a): 1-5%; and Brattle (2014): 15-42%.
Event Participation	% (switch success rate)	94%	SH and CAC DLC and PCT programs range from 64% to 96%. Navigant (2012) had 94%, matching participation for ConEd (2012) and NIPSCO (2012) CAC programs.
Ramp Rate	Number of years to reach maximum achievable potential	20	Mirrors the 20-year decline of the existing DLC products.

Table B-16. Small Commercial DLC Electric Resistance Water Heaters Switch Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$0	Existing program - no setup cost.
O&M Cost	$ per participant per year	$50	Average non-incentive costs from 2016/2017 LG&E and KU data. Accounts for program administrative costs and communications costs for load control devices.
Equipment Cost	$ per new participant	$0	No new participants modeled.
Marketing Cost	$ per new participant	$0	Marketing costs accounted for in O&M costs.
Incentives (annual)	$ per participant per year	$5	Based on LG&E and KU Website: https://lge-ku.com/commercial-demand-conservation/small
Incentives (one time)	$ per new participant	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	LG&E: 0.5%, KU: 0.4%	Based on observed decline in LG&E and KU's DLC switch counts from 2017 to 2020.
Eligibility	% of customer count (e.g. equipment saturation)	100%	Customer count was manually adjusted to reflect current water heat switch counts - eligibility for this adjusted customer count is 100%.
Peak Load Impact	kW per participant (at meter)	0.35	PSO and OG&E (2014) saw savings of 1.0kW/AC + 0.35/WH. PacifiCorp (2013) 1.0 kW/AC + 0.5 kW/WH.
Program Participation	% of eligible customers	100%	Eligible customers were adjusted to only reflect program participants - program participation is 100%.
Event Participation	% (switch success rate)	50%	LG&E and KU were observing approximately a 50% failure rate among older switches.
Ramp Rate	Number of years to reach maximum achievable potential	1	Existing program - 100% ramped up in start year. Product ramp rate set to zero from 2028 onwards due to expectation of program cancellation.

Table B-17. Residential Behavioral Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per kW pledged per year	$67	BPA assumption (Cadmus 2018) of $89/kW-year (or $4/participant) assumes implementing Res Behavior DR as a stand-alone product. However, Cadmus assumes it would cost $67/kW-year (or $3/participant) to add Res Behavior DR to PSE's existing energy efficiency behavioral program.
Equipment Cost	$ per new kW pledged	$0	Participants must have a device to receive messages.
Marketing Cost	$ per new kW pledged	$0	Included in O&M costs.

Parameters	Units	Values	Notes
Incentives (annual)	$ per kW pledged per year	$0	In line with BPA assumption (Cadmus 2018).
Incentives (one time)	$ per new kW pledged	$0	
Attrition	% of existing participants per year	3%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018).
Eligibility	% of segment/end-use load	100%	AMI dependency captured in ramp rate - eligibility value set to 100%.
Peak Load Impact	% of eligible segment/end-use load	1%	PGE Flex Pricing and Behavioral Demand Response Pilot (Cadmus 2018).
Program Participation	% of eligible segment/end-use load	20%	In line with BPA assumption (Cadmus 2018).
Event Participation	%	100%	Peak load impact percentage accounts for event participation rate.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350 and standard product roll out ramp rate.

Table B-18. Residential CPP without Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.

Parameters	Units	Values	Notes
Peak Load Impact	% of eligible segment load	Varies by end use	Cadmus (2015): 12%; Cadmus(2017): 12%; Applied (2017): 12.5%; Xcel Energy (2015): 14.8%. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	100%	Peak load impact already takes into account of event participation.
Ramp Rate	Number of years to reach maximum achievable potential	8	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-19. Residential CPP with Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI. Enablement technology is assumed to already be installed.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	5%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	For cool central, heat central, and heat pump, use 40% based on: Oklahoma (2011) weekday average event day impact for TOU-CP: 38.8%; DTE (2014) average impact during event hours: 44.5%; Nexant (2017b) reported 44.6% for SDG&E. For other end uses, use 12% as consistent with Res CPP-No Enablement. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.

Parameters	Units	Values	Notes
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	85%	Peak load impact already takes into account of event participation. But adjusted down for cooling/heating adjustment.
Ramp Rate	Number of years to reach maximum achievable potential	30.5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350 and on smart thermostat growth. Cadmus conservatively estimated 10% smart thermostat saturation in 2023 and 3.3% annual growth in saturation. To inform this, Cadmus relied on data from the Northwest Residential Building Stock Assessment, Wisconsin Focus, and NYSERDA baseline studies. LG&E and KU currently does not offer incentives for smart thermostats, therefore Cadmus assumed smart thermostats saturations conservatively.

Table B-20. Residential CPR without Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	$ per kWh	$1.10	Incentive cost based a $/kWh incentive range of $0.95 to $1.25 from Consumer Energy and Baltimore Gas and Electric: https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx and https://peakpowersavers.com/time
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assuming similar to CPP.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	Cadmus (2015): 12%; Cadmus(2017): 12%; Applied (2017): 12.5%; Xcel Energy (2015): 14.8%. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E

Parameters	Units	Values	Notes
			moved out of pilot to a full program with 20% participation.
Event Participation	n/a	100%	Peak load impact already takes into account of event participation.
Ramp Rate	Number of years to reach maximum achievable potential	7	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-21. Residential CPR with Enablement Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$150,000	LG&E KU Demand Response Study assume a 15% adder cost. This value represents an average over the lifetime of the program. SDG&E (2017): $280,000; Applied (2017): $75,000. Cadmus is assuming 1 FTE (split between utilities).
Equipment Cost	$ per new participant	$0	Does not include cost of AMI as LG&E and KU already intend to implement AMI. Enablement technology is assumed to already be installed.
Marketing Cost	$ per new participant	$25	Marketing costs are based on one-half hour of staff time valued at $50/hour (fully-loaded).
Incentives (annual)	$ per kWh	$1.10	Incentive cost based a $/kWh incentive range of $0.95 to $1.25 from Consumer Energy and Baltimore Gas and Electric: https://www.bge.com/SmartEnergy/ProgramsServices/Pages/SmartEnergyRewards.aspx and https://peakpowersavers.com/time
Incentives (one time)	n/a	$0	This product does not provide one time incentives.
Attrition	% of existing participants per year	5%	Assuming similar to CPP.
Eligibility	% of segment load	1	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	Varies by end use	For cool central, heat central, and heat pump, use 40% based on: Oklahoma (2011) weekday average event day impact for TOU-CP: 38.8%; DTE (2014) average impact during event hours: 44.5%; Nexant (2017b) reported 44.6% for SDG&E. For other end uses, use 12% as consistent with Res CPP-No Enablement. Heating/cooling set to zero depending on season, HP adjusted according to HP heating/cooling consumption percent for each season.
Program Participation	% of eligible segment load	10%	Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters). SMUD had a significant pilot that reached 5% participation and OG&E moved out of pilot to a full program with 20% participation.
Event Participation	n/a	85%	Peak load impact already takes into account of event participation. But adjusted down for cooling/heating adjustment.

Parameters	Units	Values	Notes
Ramp Rate	Number of years to reach maximum achievable potential	30.5	Based on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Table B-22. Residential Time of Use Input Assumptions

Parameters	Units	Values	Notes
Setup Cost	$ (one time cost)	$150,000	Assumes 1 FTE (split between utilities).
O&M Cost	$ per year	$0	Assume program is new rate class and requires minimal additional maintenance.
Equipment Cost	$ per new participant	$0	No equipment needed to participate
Marketing Cost	$ per new participant	$30	Based on one-half FTE of staff time valued at $50/hour (fully-loaded) with an additional 25% to reflect additional effort.
Incentives (annual)	n/a	$0	This product does not provide incentives.
Incentives (one time)	n/a	$0	
Attrition	% of existing participants per year	2%	Based on Cadmus 2016 and 2017 LG&E and KU DR potential studies.
Eligibility	% of segment load	100%	All residential customers are eligible.
Peak Load Impact	% of eligible segment load	10%	LG&E KU's price ratio of 4.07 equated to a 7% to 9% potential on a program price responsiveness curve. Benchmarking of summer programs includes: 7.4% Xcel (2015); 8% PSO (2014); 9% SMUD (2014); Nevada Energy 10.74% (2015); 14% OG&E.
Program Participation	% of eligible segment load	20%	Participation estimates align with recent Xcel Energy's price responsiveness survey and program benchmarking. Pilot programs have lower penetration as they are not fully deployed (FERC data showed less than 1% of total residential meters): SMUD had a significant pilot that reached 5%; TVA potential 5%. OG&E moved out of pilot to a full program with 20%. PGE potential used 2% increasing to 40% in 2028;
Event Participation	n/a	100%	Event participation is captured in the average load impact.
Ramp Rate	Number of years to reach maximum achievable potential	9	Based on uptake of rate program and on LG&E and KU AMI deployment outlined in LG&E and KU Rate Case Numbers 2020-00349 and 2020-00350.

Appendix C. Supplemental Results Figures and Tables

The figures and tables below show supplemental summaries of the results presented.

Figure C-1. DLC Products - Summer Market Potential

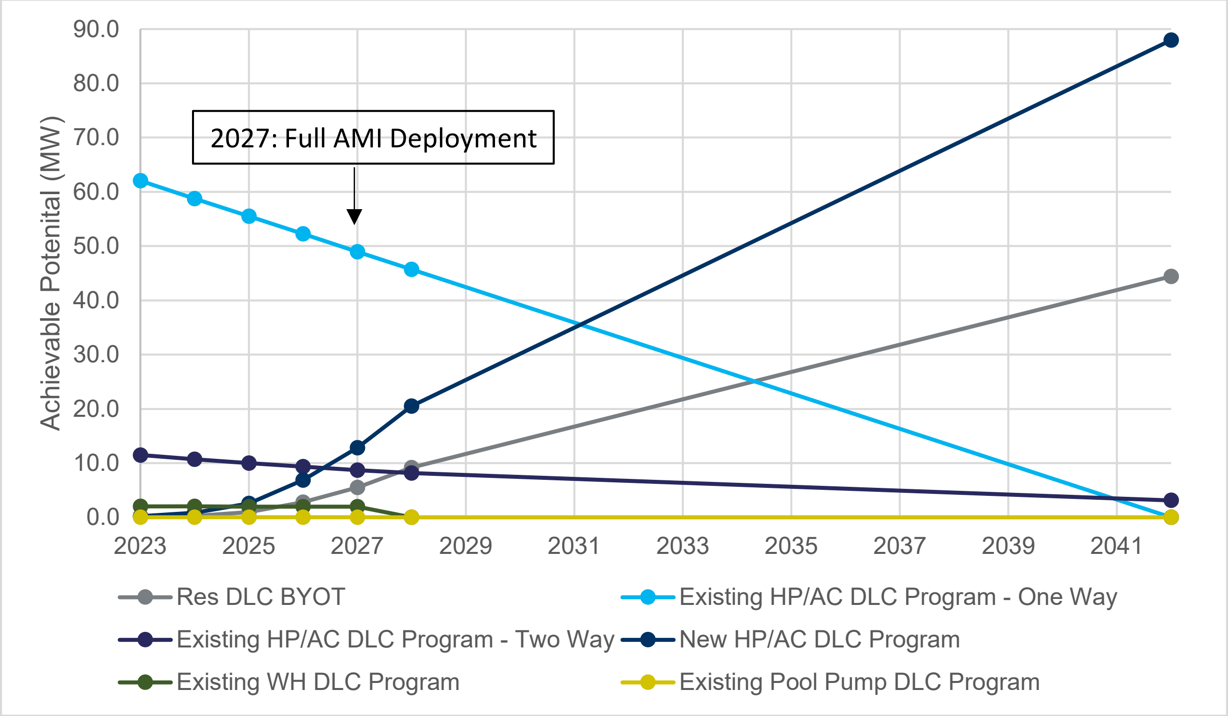

Figure C-2. Curtailment Products - Summer Market Potential

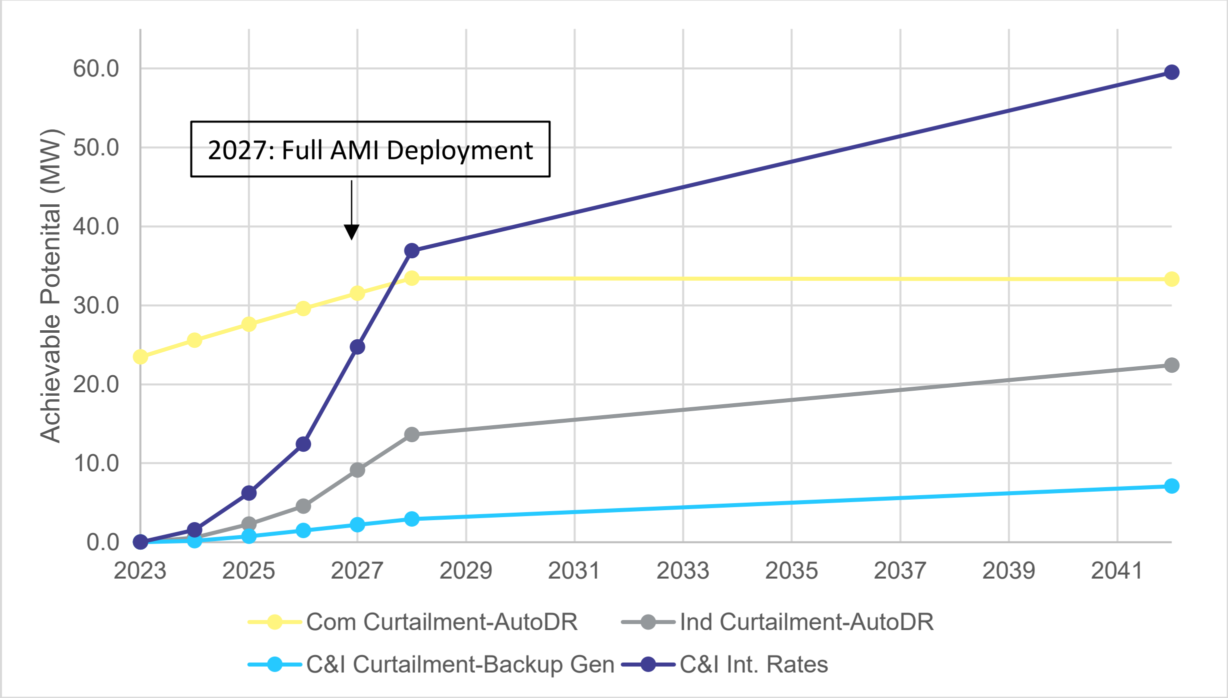

Figure C-3. Pricing/Other Products - Summer Market Potential

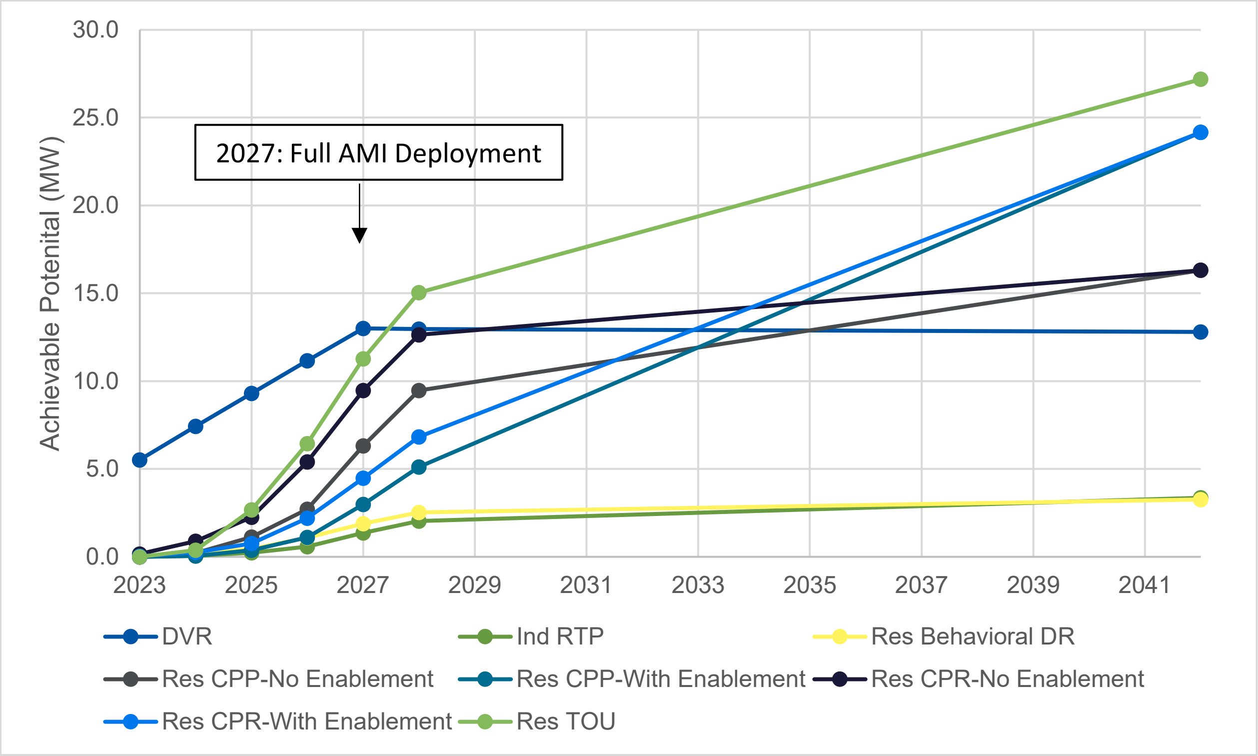

Figure C-4. DLC Products - Winter Market Potential

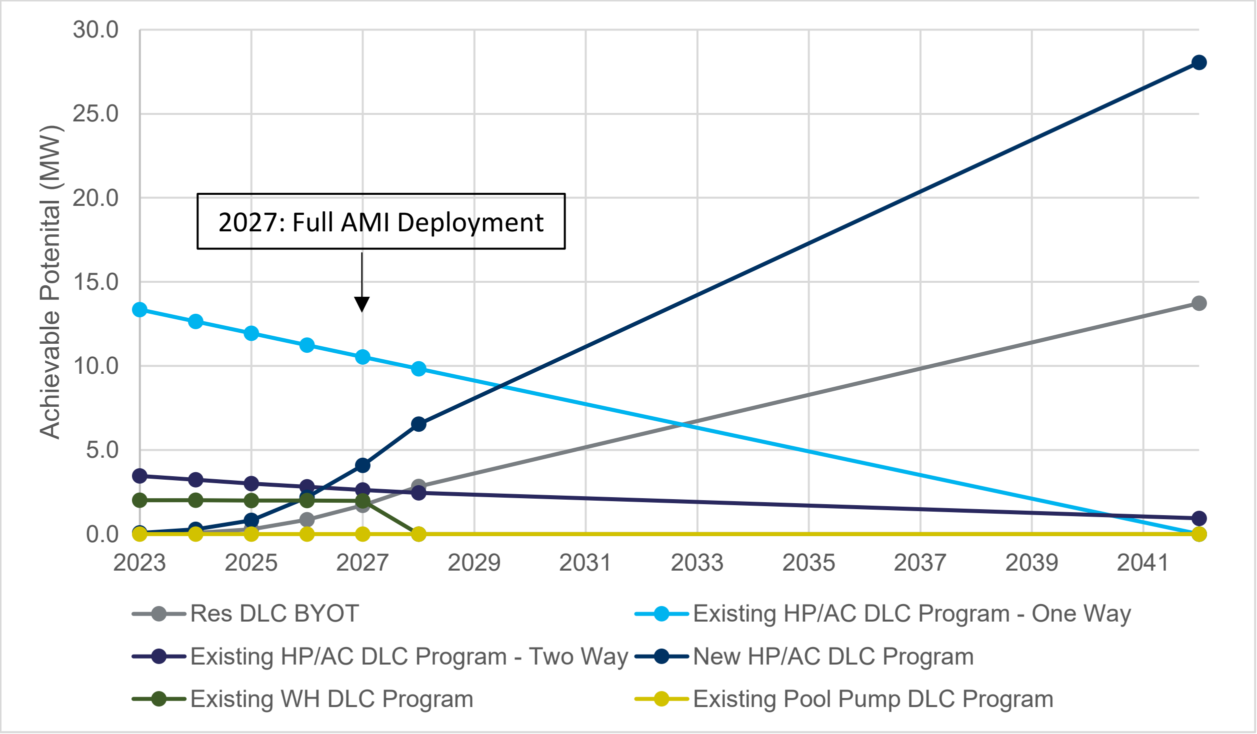

Figure C-5. Curtailment Products - Winter Market Potential

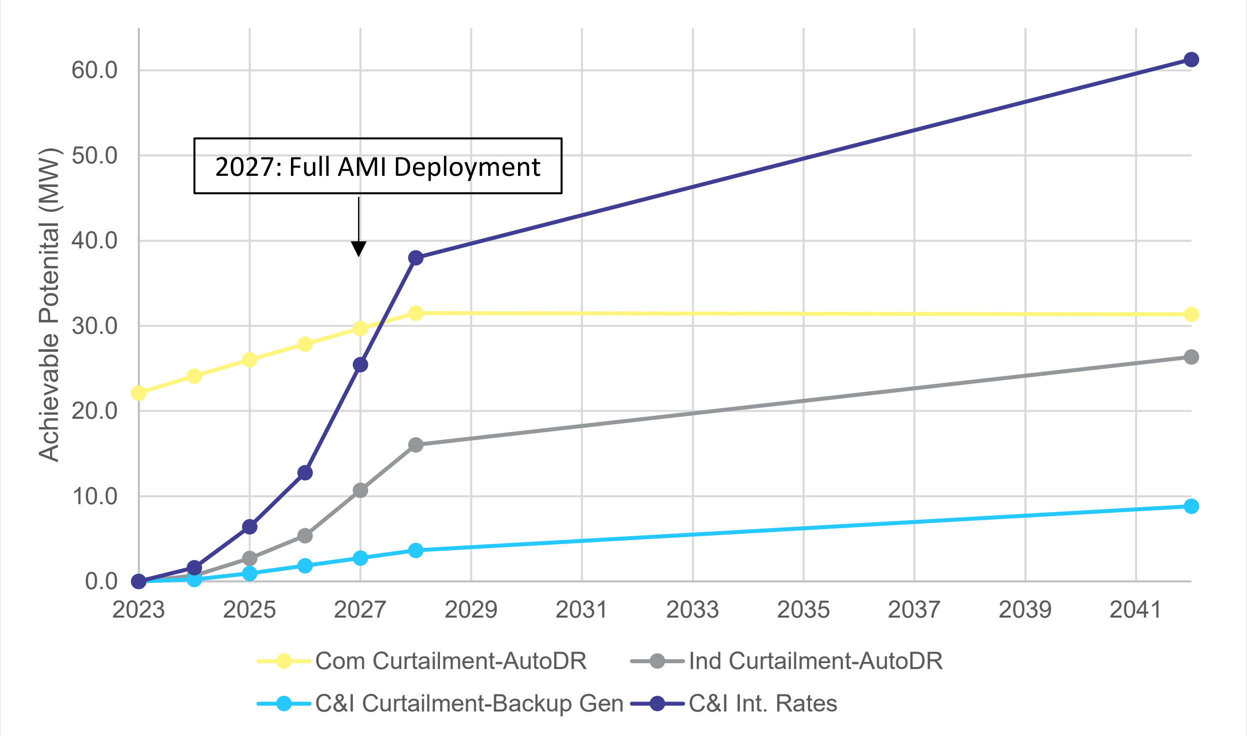

Figure C-6. Pricing/Other Products - Winter Market Potential

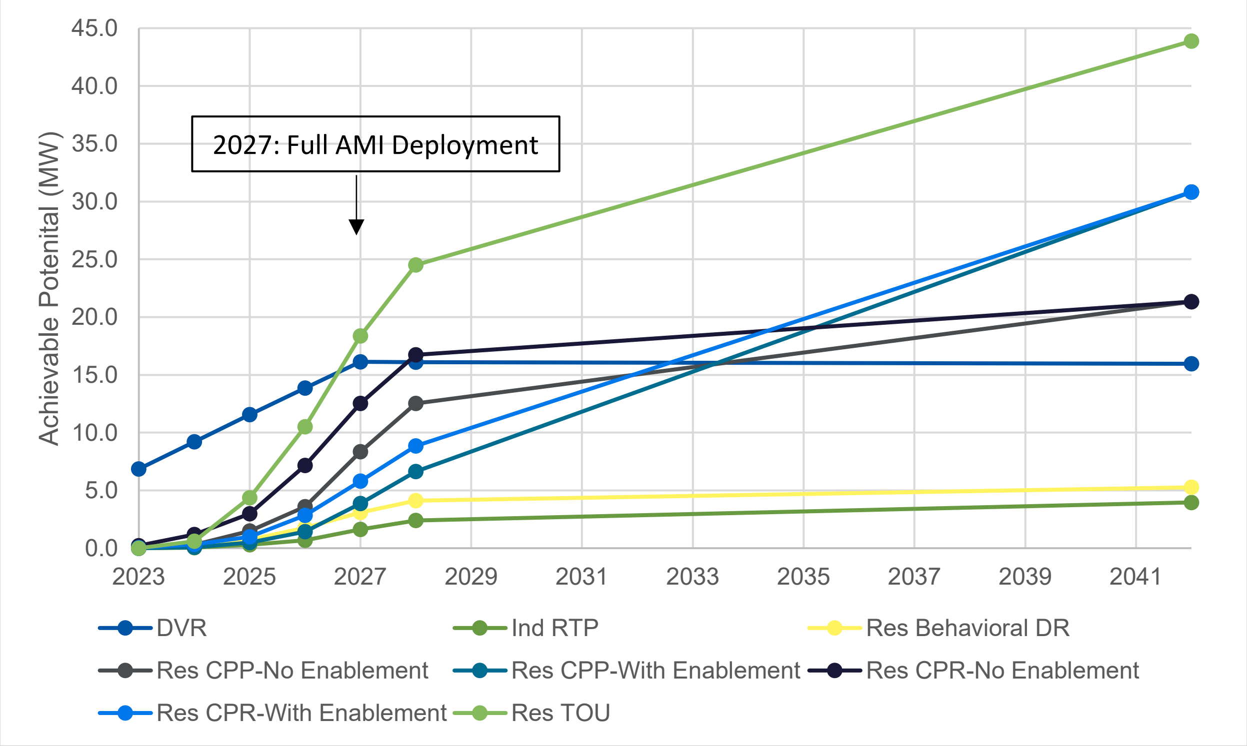

Table C-1. Cost-Effectiveness Results

Product	Benefit-Cost Ratio	
	Summer	Winter
C&I Curtailment-Backup Gen	0.30	0.37
Existing WH DLC Program	0.48	0.48
New HP/AC DLC Program	0.77	0.99
Res DLC BYOT	0.85	1.04
Ind RTP	1.22	1.43
Existing HP/AC DLC Program - One Way	1.15	1.06
Res Behavioral DR	1.21	1.25
Existing HP/AC DLC Program - Two Way	1.55	2.00
Ind Curtailment-AutoDR	1.91	2.16
Existing Pool Pump DLC Program	1.89	N/A
Res CPR-No Enablement	2.42	2.84
Res CPR-With Enablement	2.55	2.48
Res CPP-No Enablement	2.74	3.62
Com Curtailment-AutoDR	2.99	2.62
Res CPP-With Enablement	3.38	4.35
Res TOU	4.33	7.04
C&I Int. Rates	8.28	8.44
DVR	9.44	9.67

Table C- 2. Tipping Point Analysis Results

Product	Tipping Point Cost	
	Summer	Winter
C&I Curtailment-Backup Gen	$320	$257
Existing WH DLC Program	$183	$183
New HP/AC DLC Program	$114	$89
Res DLC BYOT	$103	$84
Ind RTP	$78	$66
Existing HP/AC DLC Program - One Way	$76	$83
Res Behavioral DR	$73	$70
Existing HP/AC DLC Program - Two Way	$57	$44
Ind Curtailment-AutoDR	$50	$44
Existing Pool Pump DLC Program	$47	N/A
Res CPR-No Enablement	$36	$31
Res CPR-With Enablement	$35	$35
Res CPP-No Enablement	$35	$26
Com Curtailment-AutoDR	$29	$34
Res CPP-With Enablement	$28	$22
Res TOU	$22	$13
C&I Int. Rates	$11	$11
DVR	$9	$9

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.38

Responding Witness: Stuart A. Wilson

Q-1.38. At page 5-15 of Volume I, the Companies states "To assess the potential for new DSM programs, the PROSYM production cost model from ABB was used to model annual production costs for the resource plan in the base energy requirements, base fuel case." With respect tothis statement, please answer the following:

a. Precisely how was the PROSYM modeling used to assess potential for DSM?

b. What specific pieces of its PROSYM modeling did the Companies use to assess the potential for new DSM?

c. What were the results of that assessment? Please provide them.

d. Provide any documentation in electronic spreadsheet format with all formulas and links intact which support your responses to subparts a, b, and c.

A-1.38.

a. The Companies reviewed PROSYM results to identify potential resources that are expected to dispatch at low capacity factors as candidates that could be substituted for DSM programs. As stated in section 4.4 of the Long-Term Resource Planning Analysis in Vol. III of the IRP, the 200 MW of battery storage added in 2035 and 2036 is forecast to operate at a capacity factor of less than 1 percent, and is primarily for serving peak load. Successful deployment of DSM programs could reduce or defer the need for peaking resources, particularly for battery storage where their modular nature allows for more custom project sizes. Also see the response to PSC 1-4(a).

b. The Companies analyzed capacity factors in the base load, base fuel case. See the response to part (a).

c. The analysis simply identified the types of resources that can potentially be avoided or deferred by new DSM programs. See the response to part (a).

d. See the responses to parts (a-c), and the response to SREA 1-7(c). The Companies did not evaluate any specific programs and relied solely on evaluation of capacity factors as a means of assessing DSM potential.

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.39

Responding Witness: John Bevington / Stuart A. Wilson

Q-1.39. Page 5 – 3 of the IRP states, "Due to the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique because annual peak demands can occur in both the summer and winter months." With respect to this statement please answer the following:

a. What is driving the increasing penetration of electric heating in the Companies' service territories?

b. Do the Companies offer any efficiency programs which target electric heating? If so, what are the annual projected kWh and kW savings from this program?

c. If the Companies offer an efficiency program targeting electric heating what measures does it incentivize, if any?

d. Have the Companies sought to implement an electric heating demand response program? If not, why not? If so, please provide any documentation describing the Companies' efforts.

A-1.39.

a. See the response to Lou Metro 1-3.

b. No.

c. See the response to part (b).

d. See the response above to Question No. 37 e.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.40

Responding Witness: John Bevington

Q-1.40. Please provide program descriptions of the demand response programs in Table 5-1. Are these programs open to new enrollment?

A-1.40. For detailed program descriptions of the demand response programs, please see Section 3, of Exhibit GSL-1, from Case No. 2017-00441.[8] Both programs are open to a limited number of new enrollments.

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[8] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.41

Responding Witness: John Bevington

Q-1.41. Do the Companies provide any formal demand response program offerings to industrial customers? If so, please provide the details of those offerings including incentive level paid, administrative fees, enrollment fees, notification times etc. If the Companies do not offer any formal demand response programs offerings to industrial customers, please detail the steps the Companies have taken to explore the option of doing so.

A-1.41. Yes, the Large Nonresidential Demand Conservation Program is open to industrial customers who have not opted out of DSM. For a detailed program description, please see Section 3.2, of Exhibit GSL-1, from Case No. 2017-00441.[9]

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[9] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.42

Responding Witness: John Bevington

Q-1.42. Refer to Volume III, page 4, stating: "Similar to the process in 2017, the Companies have again engaged with Cadmus, Inc. to assist in the development of the upcoming filing." What programs does the Company intend to request approval of? Please provide any documentation supporting your answer.

A-1.42. See the response to PSC 1-4.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.43

Responding Witness: Stuart A. Wilson

Q-1.43. Please provide a breakdown of peak MW and MWH of industrial load by sector and season. This could be provided using NAICS or SIC or a comparable segmentation..

A-1.43. The Companies develop forecasts for their largest customers individually. The table below summarizes electricity consumption for these customers by sector from 2022-2030 (sectors assignments were made by the Companies). In total, these goods-producing customers accounted for 45% of industrial class sales in 2021.

Season[10]	Year	Appliance	Auto Related	Cement	Chemical	Mining	Paper/Pulp	Steel	Other
Summer	**2022**	101,157	548,249	110,560	439,077	109,852	118,331	700,778	188,693
Summer	**2023**	102,657	547,135	110,560	421,299	111,237	119,760	699,822	187,745
Summer	**2024**	103,407	550,224	110,560	433,835	110,419	119,760	700,677	188,693
Summer	**2025**	104,157	549,117	110,560	434,491	108,847	119,760	700,863	188,693
Summer	**2026**	104,157	548,013	110,560	411,283	107,089	119,760	700,892	187,745
Summer	**2027**	104,157	546,913	110,560	435,279	105,216	119,760	700,892	188,693
Summer	**2028**	104,157	545,817	110,560	435,614	104,144	119,760	700,892	188,693
Summer	**2029**	104,157	544,724	110,560	435,698	103,617	119,760	700,892	188,693
Summer	**2030**	104,157	543,634	110,560	435,698	103,197	119,760	700,892	188,693
Winter	**2022**	92,843	496,745	93,294	434,149	111,850	115,139	673,926	175,161
Winter	**2023**	94,343	497,867	93,294	430,791	113,679	117,996	671,903	176,109
Winter	**2024**	95,670	503,978	93,801	433,197	114,197	118,682	677,223	175,877
Winter	**2025**	95,843	500,119	93,294	431,332	112,306	117,996	673,976	175,161
Winter	**2026**	95,843	499,150	93,294	423,091	110,488	117,996	674,154	176,109
Winter	**2027**	95,843	498,184	93,294	432,001	108,694	117,996	674,154	176,109
Winter	**2028**	96,420	500,085	93,801	434,580	107,763	118,682	678,032	176,825
Winter	**2029**	95,843	496,261	93,294	432,287	106,719	117,996	674,154	176,109
Winter	**2030**	95,843	495,304	93,294	432,313	106,200	117,996	674,154	176,109

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[10] Summer is defined as May through October. Winter is defined as November through April.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.44

Responding Witness: Stuart A. Wilson

Q-1.44. Please refer to Table 21 on page 23 of the 2021 IRP Long-Term Resource Planning Analysis. Please provide the energy and peak DSM savings that were modeled for the base load and base fuel case.

A-1.44. See the response to Question No. 38.

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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.45

Responding Witness: Stuart A. Wilson

Q-1.45. Please provide the winter and summer capacity contributions assumed for the existing DSM programs across the IRP planning horizon.

A-1.45. See Tables 14 and 15 on pages 17 and 18, respectively, of the Long-term Resource Planning Analysis in Volume III. Summer and winter capacity contributions for the Companies' dispatchable DSM programs are listed in the rows labeled "Demand Conservation Program" or "DCP." Table 17 contains the estimated impact of non-dispatchable DSM programs on summer peak. The Companies do not estimate the impact of these programs on winter peak. See the response to Question No. 30.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Case No. 2021-00393

Question No. 1.46

Responding Witness: John Bevington

Q-1.46. Please provide the total program costs for each of the existing DSM programs.

A-1.46. For program costs, please see Sections 2 and 3 of Exhibit GSL-1, from Case No. 2017-00441.[11] Note that the Commission did not approve the School Energy Managers Program (SEMP).

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[11] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.47

Responding Witness: John Bevington

Q-1.47. Please provide the measure life and measure savings for each of the existing DSM programs.

A-1.47. See attachment being provided in Excel format.

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors'
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.48

Responding Witness: John Bevington

Q-1.48. Please refer to page 5-11 of the IRP where it says "The Companies did not directly evaluate new demand-side management ("DSM") programs in this IRP." Please explain why the Companies did not evaluate new DSM programs in this IRP.

A-1.48. See the response to PSC 1-4a.

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Response to Joint Intervenors'
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Case No. 2021-00393

Question No. 1.49

Responding Witness: John Bevington

Q-1.49. Please refer to page 5-44 of the IRP where it says "As AMI is implemented, the Companies plan to evaluate new DSM mechanisms that leverage AMI data and communications through the development of pilot programs."

a. Please explain what pilot programs the Companies are considering.

b. Please explain what new DSM programs might be offered through the use of the AMI data.

A-1.49.

a. Though it is still very early in the process, and the list is far from complete, the Companies plan to look at Peak Time Rebates, Behavioral Marketing (similar to the previously offered Smart Energy Profile program), as well as multiple functionality/offerings related to customers interfacing AMI data similar to information presented in the MyMeter portal. The Companies plan to perform a thorough and comprehensive review of all available options and work with the DSM Advisory Group.

b. See the response to part (a).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILTIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.50

Responding Witness: John Bevington / Stuart A. Wilson

Q-1.50. For each of the Companies' DSM-EE Programs, please provide the Companies' most recent cost effectiveness test screening and answer the following requests:

a. Please explain in detail how avoided costs were determined for each cost benefit test used (e.g., Total Resource Cost Test, Utility Cost Test, Participant Cost Test, Rate Impact Measure Test, Societal Cost Benefit Test).

b. If the Companies have not used the Societal Cost Benefit Test to evaluate the DSM-EE Programs, please explain why not in full.

c. Please provide the values for each element of the avoided cost categories listed below. Please provide the source of the values used and state whether the values are in nominal dollars or in real, inflation-adjusted dollars.
    i. Energy cost
    ii. Capacity cost
    iii. Capacity reserves (if not included in capacity costs)
    iv. Natural gas price
    v. Environmental externalities, including avoided methane loss from gas transmission, distribution, and storage infrastructure
    vi. Line losses, for energy and peak (please specify if the estimate is based on average or marginal line loss rates).

d. Please state whether any of the following avoided cost categories listed below are included in the Companies' avoided cost calculation and if so, please provide the value, source of the value, and state whether the value is in normal dollar or in real, inflation-adjusted dollars.
    i. Ancillary services
    ii. Transmission and distribution
    iii. Non-energy benefits ("NEBs") (please specify which NEBs are included)

iv. Increased reliability
v. Reduced risk (e.g., reduced exposure to future fuel price volatility, future environmental regulation compliance costs, uncertainties of demand forecasts and related capital investments, etc.)
vi. Reduced credit and collection costs
vii. Reduced pollution and environmental damage
viii. Reduced negative health impacts
ix. Any other avoided cost values incorporated into cost-effectiveness analyses.

A-1.50. For a summary of the most recent cost-effectiveness tests, please see Table D (page 23 of 182), in Exhibit GSL-1, from Case No. 2017-00441.[12]

a. Avoided energy costs and avoided capacity costs are inputs into the cost-effective scoring model utilized by Cadmus, Inc., called Portfolio Pro. For a detailed description of the process, and each test and their respective components, please see Section 1.4, in Exhibit GSL-1, from Case No. 2017-00441. Additionally, Table C in Section 1.4 shows the tests and their components side by side.

b. The Companies have not used the Societal Cost Benefit Test to evaluate the DSM-EE Programs. The Commission stated in its final order in the Companies' most recent DSM-EE Program Plan proceeding, Case No. 2017-00441:

> In evaluating the cost-effectiveness of the proposed DSM/EE programs, *the Commission disagrees with MHC's recommendation to include the cost of non-energy factors and benefits*. KRS Chapter 278 creates the Commission as a statutory administrative agency empowered with "exclusive jurisdiction over the regulation of rates and service of utilities." *The Commission has no jurisdiction over environmental impacts, health, or other non-energy factors that do not affect rates or service*. Lacking jurisdiction over these non-energy factors, the Commission has no authority to require a utility to include such factors in benefit-cost analyses of DSM programs. As LG&E/KU correctly note, it does not follow from their citing in 2014 of the potential avoidance of environmental compliance costs in rates in support of the construction of a 10 MW solar facility that the Commission has jurisdiction in a DSM case to require an analysis of non-energy criteria such as environmental and

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[12] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

> health factors that have no impact on rates. *MHC's claim that including externalities in the California tests would result in greater DSM benefits to residential customers is unpersuasive ….*[13]

c. The figures below are all in nominal dollars.

   i. The Marginal Cost (Avoided Energy Cost) used in the last DSM Filing was approximately $0.028/kWh (the 20-year average in nominal dollars). (Please also see page 9 of 182 in Exhibit GSL-1 from Case No. 2017-00441 for more information about avoided energy costs.[14])

   ii. The Avoided Capacity Cost used in the last DSM Filing was $0/kW-year in nominal dollars. (Please also see page 9 of 182 in Exhibit GSL-1 from Case No. 2017-00441 for more information about avoided capacity costs.[15])

   iii. The Companies did not estimate avoided capacity reserves cost in this avoided cost calculation. See the response to part (c-ii).

   iv. The annual average Henry Hub natural gas price forecast used in the avoided energy cost discussed in part (c-ii) was from the Companies' 2018 Business Plan and is shown in the following table in nominal $/MMBtu.

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[13] *Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441, Order at 28-29 (Ky. PSC Oct. 5, 2018) (emphases added).

[14] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

[15] Available at https://psc.ky.gov/pscecf/2017-00441/rick.lovekamp%40lge-ku.com/12062017050458/LGE_KU_Testimony_and_Exhibits.pdf.

2018	2.98		2035	5.60
2019	2.92		2036	5.74
2020	2.98		2037	5.88
2021	3.10		2038	6.02
2022	3.25		2039	6.16
2023	3.44		2040	6.30
2024	3.64		2041	6.44
2025	3.87		2042	6.58
2026	4.11		2043	6.72
2027	4.36		2044	6.86
2028	4.62		2045	7.00
2029	4.76		2046	7.14
2030	4.90		2047	7.28
2031	5.04		2048	7.42
2032	5.18		2049	7.56
2033	5.32		2050	7.70
2034	5.46			

v. These are not included in the avoided cost calculation.

vi. These are not included in the avoided cost calculation.

d. None of the listed categories were included in the Companies’ avoided cost calculation.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.51

Responding Witness: Stuart A. Wilson

Q-1.51. Refer to Vol. I, Tables 5-15 and 5-16. Within each column, do the dollar amounts correspond to the stated capacity values? (e.g., for a SCCT unit with 220 MW summer capacity, the estimated capital cost would be $885/kW). If not, please explain in detail.

a. What was the assumed (i) capital cost and (ii) fixed O&M cost for each 100 MW increment of 4-hour battery storage?

b. What was the assumed (i) capital cost and (ii) fixed O&M cost for each 100 MW increment of 8-hour battery storage?

c. On what basis do the Companies conclude that 100 MW is a "typical" installation size for each of (i) battery storage (footnote 37), (ii) solar (footnote 40), and (iii) wind (footnote 40)?

d. Do the Companies have analysis or documentation supporting their characterization of 100 MW as a "typical" installation size for each of (i) battery storage, (ii) solar, and (iii) wind? If so, please produce that analysis or supporting documentation.

A-1.51. The capital costs are listed in $/kW and are applicable to any reasonable capacity for a given resource. To determine the capital costs in total dollars, the capital cost in $/kW would be multiplied by the average capacity value (average of summer and winter capacity).

a. See Tables 5-15 and 5-16 and the response above. The capital cost in $/kW and the fixed O&M cost in $/kW-yr can be applied to the capacity listed (or any other reasonable capacity for a given resource).

b. See the response to part (a).

c. Tables 5-15 and 5-16 show summer and winter capacities of “1+” for battery storage and “100+” for solar and wind resources. The “+” in the tables and the footnotes regarding “typical” installations were meant to convey that most battery storage facilities are at least 1 MW, and most solar and wind facilities are at least 100 MW in total. The Companies chose to model all three technology types at 100 MW increments for simplification.

d. The Companies relied on their knowledge of the industry in general regarding typical utility-scale capacities for the cited technologies. As noted in the response to part (c), the Companies did not state that 100 MW batteries were typical; rather, utility-scale installations of 1 MW or more are typical, and the Companies modeled batteries in 100 MW increments.

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Response to Joint Intervenors'
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Case No. 2021-00393

Question No. 1.52

Responding Witness: Stuart A. Wilson

Q-1.52. Please provide the spreadsheets with all formulas and links intact used to develop the inputs for the PLEXOS and PROSYM including but not limited to spreadsheets used to develop Build Cost assumptions.

A-1.52. See the response to Question No. 3. These spreadsheets are in the folder locations as follows.

- 2022Plan
- \0283_2021IRP\ResourceAssessment\PLEXOS\20211008_2021IRP - 26WRM scenarios
- \0283_2021IRP\ResourceAssessment\ReferenceCase\ModelInputs\Support
- \0283_2021IRP\SupplySideScreening

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Response to Joint Intervenors'
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Question No. 1.53

Responding Witness: Stuart A. Wilson

Q-1.53. Did the Companies evaluate the potential for adding pumped storage capacity to their systems including retrofitting existing dam within or near their service territories? If not, why not? If so, provide any documents summarizing that assessment.

A-1.53. The Companies did not evaluate new or retrofitted pumped storage. See Volume III, Resource Screening Analysis, Section 2.1.3, where the Companies state, the "land-use requirements for pumped hydroelectric facilities make these storage technologies unsuitable in the Companies' service territories."

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.54

Responding Witness: Stuart A. Wilson

Q-1.54. Please refer to table 5-16 on page 5-40 of the IRP. Do the summer and winter capacity contributions for solar and wind resources remain constant throughout the planning horizon at the values provided in Table 5-16? If not, please provide the summer and winter capacity contributions for solar and wind across the entire planning horizon.

a. Please provide the analysis supporting the development of the summer and winter capacity contribution assumptions for solar and wind resources.

b. Please provide the summer and winter capacity contribution assumptions for 4- and 8-hour battery storage resources.

c. Please confirm if battery storage resources could be selected in partial units within the capacity expansion model or if they could only be added in 100 MW increments.

d. Please confirm if the Investment Tax Credit ("ITC") was assumed to be credited in the first year of the project or normalized for new solar resources. If normalized, please explain the Companies' justification for this assumption.

e. Please provide any resource constraints that were placed on the new supply side resources within the capacity expansion modeling.

A-1.54. Yes, the Companies assume the summer and winter capacity contributions for solar and wind resources remain constant throughout the planning horizon.

a. See the response to SREA 1-14(b).

b. Because battery storage resources are dispatchable resources, their summer and winter capacity contribution is assumed to be 100%.

c. The Companies modeled battery storage resources in 100 MW increments with no allowance for partial units.

d. The ITC was assumed to be credited in the first year of the project.

e. New simple cycle combustion turbines were limited to a maximum capacity factor of 20 percent. Solar and wind PPAs were considered to be “must-take.” New batteries’ state of charge was constrained to between 5 percent and 95 percent of nameplate storage capacity.

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Case No. 2021-00393

Question No. 1.55

Responding Witness: Stuart A. Wilson

Q-1.55. Please refer to page 12 of the 2021 IRP Long-Term Resource Planning Analysis where it says, "For purposes of this analysis, the Companies are assuming the Investment Tax Credit ("ITC") will be expanded to apply to battery storage installation regardless of whether or not they are co-located and associated with solar generation." Please confirm if the costs reported for 4 and 8 hour battery storage resources in Table 5-16 on page 5-40 of the IRP incorporate the ITC.

a. Please explain if the ITC assumption for battery storage resources was credited in the first year of the project or normalized. If normalized, please explain the Companies' justification for this assumption.

A-1.55. The costs reported in Table 5-16 do not incorporate the ITC.

a. The ITC was assumed to be credited in the first year of the project.

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Response to Joint Intervenors'
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Case No. 2021-00393

Question No. 1.56

Responding Witness: Stuart A. Wilson

Q-1.56. Please refer to Table 5-15.

a. Did the Companies assume that all new combined cycle units would be installed with carbon capture? If so, please explain why that assumption was made.

b. What percentage of CO_2 is assumed to be captured?

c. What sink for the captured CO2 is assumed?

d. What capture technology is assumed and why?

A-1.56.

a. Yes. See the Executive Summary of Volume III, Resource Screening Analysis where the Companies state, "Based on the Biden administration's energy policy and the national focus on moving to clean energy, the current environment does not support the installation of NGCC without CCS due to its CO_2 emissions."

b. 90%.

c. The IRP analysis does not contemplate a sink or third party use for the captured CO_2. NGCC with CCS was not selected as a least-cost resource.

d. According to NREL's 2021 ATB online documentation, "solvent-based post-combustion carbon capture technology designed to capture 90% of the carbon in the treated flue gas" is assumed for the NGCC with CCS resource option.[16]

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[16] https://atb.nrel.gov/electricity/2021/fossil_energy_technologies

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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.57

Responding Witness: Stuart A. Wilson

Q-1.57. Refer to Vol. III, 2021 IRP Resource Screening Analysis report at page 8.

a. What was the assumed "round-trip efficiency" used to model utility-scale lithium ion batteries?

b. Do the Companies have any analysis or documentation supporting the assumed round-trip efficiency used to model utility-scale lithium ion batteries? If so, please provide that analysis or supporting documentation.

c. What was the assumed reduction in available battery capacity (on a percentage basis, as presented on page 8 of the Vol. III, 2021 IRP Resource Screening Analysis report)?

d. Do the Companies have any analysis or documentation supporting the assumed reduction in available battery capacity? If so, please provide that analysis or supporting documentation.

A-1.57.

a. See Table 3 in Volume III, Resource Screening Analysis. The Companies assumed 85% round-trip efficiency.

b. The Companies used NREL's 2021 ATB as the basis for cost and operating inputs, which includes 85% round-trip efficiency for battery storage. Utility-scale energy storage systems have significant heating and cooling loads and inverter losses, which reduce round-trip efficiency.

c. The Companies assumed states of charge ("SOC") were limited to 5% and 95%, which results in a 10% reduction in available battery capacity.

d. This reduction in battery capacity is a global industry standard, consistent with NREL's ATB and with most manufacturer recommendations. For example, please read the user's manual for LG Chem energy storage systems.[17] Control systems for utility-scale energy storage systems typically do not allow owners or operators to charge outside of the 5 to 95% range for safety.

Over-charging or over-discharging a lithium-ion battery drastically increases the probability of thermal runaway, fire, and explosion. Many lithium-ion thermal runaway events occurred while the battery SOC was very high. For example, see the 2019 battery fire and explosion event at Arizona Public Service McMicken Energy Storage Facility in 2019.[18] When SOC is high, there is more energy stored in the battery, and higher energy-density, which allows thermal runaway to happen at lower temperatures, increasing the probability of thermal runaway and cell propagation. Research from Sandia National Laboratories in 2019 found that "thermal runaway onset temperature decreases and peak heating rate increases with SOC due to cathode destabilization."[19] For this reason, many owners of lithium-ion batteries place even stricter limits on SOC.

The Companies assume a lower-bound SOC limit of 5% in the IRP, consistent with NREL and manufacturer recommendations, for safety and battery longevity. According to a study published in Nature, SOC lower than 5% results in too little charge for cell voltage balancing. Without enough charge for cell voltage balancing, lithium-ion battery cells in series are prone to over-discharging, which may result in an internal short circuit. The damage from an internal short circuit can result in a fire during subsequent charging.[20]

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[17] LG Chem Energy Storage Users Manual. https://www.lg.com/global/business/download/resources/ess/LG%20ESS_GEN1.0VI_Residential%20Operating%20Manual_EN.pdf

[18] LG Chem Report for Commission Inquiry of Arizona Public Service Battery Incident. July 30, 2020. Site Inspection, Page 36. https://docket.images.azcc.gov/E000007939.pdf

[19] Barkholtz et al. "Multi-scale thermal stability study of commercial lithium-ion batteries as a function of cathode chemistry and state-of-charge." Journal of Power Sources 435 (2019): 226777. https://www.sciencedirect.com/science/article/abs/pii/S0378775319307487

[20] Guo *et al*. "Mechanism of the entire overdischarge process and overdischarge-induced internal short circuit in lithium-ion batteries." Scientific reports 6, no. 1 (2016): 1-9. https://www.sciencedirect.com/science/article/abs/pii/S0378775319307487?via%3Dihub

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.58

Responding Witness: Stuart A. Wilson

Q-1.58. Refer to the 2021 IRP Resource Screening Analysis document (October 2021), Section 2.1.3 at page 8, which states: "Due to construction economies of scale and existing infrastructure, the capital cost of installing two or more SCCTs at an existing site are assumed to be approximately 25 percent lower"; and the 2021 IRP Long-Term Resource Planning Analysis, Section 3.3 at page 11, which repeats the same sentence.

a. Please confirm that the referenced 25 percent reduction was made to NREL's 2021 ATB value for SCCT capital costs. If you are unable to confirm, please identify the SCCT capital cost source reduced by approximately 25 percent.

b. Please provide the analysis and supporting documentation the Companies relied on to derive an appropriate reduction to SCCT capital costs in order to account for construction at an existing site (as opposed to a greenfield site). If no such analysis or supporting documentation exists, please explain in full the Companies basis for using an approximately 25 percent discount.

c. Please confirm that the Companies included the assumption that SCCT capital costs would be approximately 25 percent lower in the capacity expansion modeling. If anything but confirmed, please explain your response.

d. Did the Companies' Resource Screening Analysis consider the capital costs of new SCCT unit(s) at a greenfield site? Please explain in full.

A-1.58.

a. Confirmed.

b. See the response to PSC 1-56.

c. Confirmed.

d. Yes. Table 3 on page 7 of the Resource Screening Analysis lists capital cost assumptions for SCCTs at a greenfield site.

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Case No. 2021-00393

Question No. 1.59

Responding Witness: Stuart A. Wilson

Q-1.59. Please provide the Companies' actual energy sales for calendar year 2021 on an annual and monthly basis, disaggregated by customer class.

A-1.59. See the table below, expressed in MWh.

Month	Residential	Commercial	Industrial	Lighting	Public Authority	Wholesale	CC Total
1	1,175,826	634,336	701,404	3,568	207,804	34,910	2,757,848
2	1,081,554	622,443	680,126	3,385	207,124	33,236	2,627,868
3	764,558	564,684	722,955	2,498	199,849	29,180	2,283,723
4	608,528	553,552	714,920	2,711	196,213	26,784	2,102,708
5	704,971	601,513	701,563	2,287	210,412	28,695	2,249,442
6	935,568	696,946	754,054	2,422	235,132	33,312	2,657,434
7	1,069,653	742,246	748,622	2,162	248,155	35,286	2,846,123
8	1,108,885	768,286	782,191	2,575	266,896	36,121	2,964,954
9	749,780	632,940	756,048	2,635	218,595	29,759	2,389,757
10	662,227	600,013	714,740	2,913	216,635	28,424	2,224,951
11	809,509	590,818	714,685	3,234	205,897	28,608	2,352,751
12	845,831	572,570	704,015	3,298	189,652	28,614	2,343,980
2021 Total	10,516,891	7,580,346	8,695,322	33,688	2,602,364	372,927	29,801,539

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Question No. 1.60

Responding Witness: Stuart A. Wilson

Q-1.60. Refer to Vol. I, Section 5.(3), page 5-21, stating that "Table 5-7 contains monthly energy requirements for 2025 as well as the percentage of total energy requirements consumed during nighttime hours."

a. Please explain (in sufficient detail to allow replication) how the total energy requirement consumed during nighttime hours was forecasted.

b. Please provide the calculations used to derive the forecasted energy requirements and percentage nighttime hours represented in Table 5-7 in native file format with formulae intact.

A-1.60.

a. See attachment being provided in Excel format.

b. See the response to part (a).

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.61

Responding Witness: Stuart A. Wilson

Q-1.61. Please produce all Appendices to the Electric Sales & Demand Forecast Process document (July 2021), including but not limited to Appendix A (referenced in Section 4.1.2) and Appendix B (referenced in Section 4.2.1).

A-1.61. See attachments 1 and 2 to the response to PSC 1-40b.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Joint Intervenors' Initial Request for Information
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Case No. 2021-00393

Question No. 1.62

Responding Witness: Stuart A. Wilson

Q-1.62. Did the Companies' load forecast assume the development of any cryptocurrency mining operations in their service territory? If so, please identify the operations and explain your assumptions in full along with supporting analyses, workpapers, and documentation (in machine-readable format with formulas intact).

A-1.62. No, not explicitly. The high load forecast contemplates the addition of two 90 MW industrial customers, but the IRP does not specify the nature of the customers' operations.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

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Case No. 2021-00393

Question No. 1.63

Responding Witness: Stuart A. Wilson

Q-1.63 Refer to section 4.5 ("Distributed Solar Generation Forecast") of the Electric Sales & Demand Forecast Process (July 2021), specifically the following statement: "Because the ITC will no longer end in 2022, the model was trained though 2019 for KU and LG&E (2018 for ODP) to flatten out a recent steep increase in adoptions, which is thought to be related to the (supposed) end of the ITC and not indicative of a continued trend."

a. Why would "the (supposed) end of the ITC" impact the ODP service territory differently than each of the KU and LG&E service territories?

b. Please explain in full the Companies' reason(s) for training the mode through 2018 for ODP to flatten out a recent steep increase as opposed to through 2019, as done for KU and LG&E.

c. Please produce the Companies' Distributed Solar Generation Forecast.

d. For each of KU, LG&E, and ODP, please provide the number and size (in kilowatts) of distributed solar generation additions in each of the last five years.

A-1.63.

a. See the response to part (b).

b. See the response to part (d). The distributed generation capacity installed in ODP in 2019 was over 3 times greater than distributed generation capacity installed from 2010 to 2018 combined and more than 15 times greater than the capacity installed in any single year prior. Because of this, 2019 was considered an outlier and the model for ODP was trained through 2018.

c. See attachment being provided in Excel format.

d. Incremental Net Metering Additions by Year from 2016

	KU		LG&E		ODP	
	Capacity (kW)	Customers	Capacity (kW)	Customers	Capacity (kW)	Customers
2016	1,042	138	1,519	258	27	3
2017	+ 480 (1,522)	+ 44 (182)	+ 297 (1,816)	+ 35 (293)	+ 9 (36)	+ 1 (4)
2018	+ 635 (2,157)	+ 56 (238)	+ 799 (2,615)	+ 70 (363)	+ 9 (45)	+ 2 (6)
2019	+ 1,286 (3,443)	+ 131 (369)	+ 1,218 (3,833)	+ 112 (475)	+ 146 (191)	+ 4 (10)
2020	+ 2,206 (5,649)	+ 214 (583)	+ 1,463 (5,296)	+ 165 (640)	+ 76 (267)	+ 11 (21)
2021	+ 5,549 (11,198)	+ 546 (1,129)	+ 2,679 (7,975)	+ 304 (944)	+ 207 (474)	+ 21 (42)

Incremental SQF & LQF Additions by Year from 2016

	KU		LG&E	
	Capacity (kW)	Customers	Capacity (kW)	Customers
2016	1,545	7	0	0
2017	+ 60 (1,605)	+ 1 (8)	+ 787 (787)	+ 1 (1)
2018	+ 1,167 (2,772)	+ 5 (13)	+ 477 (1,264)	+ 3 (4)
2019	+ 0 (2,772)	+ 0 (13)	+ 529 (1,793)	+ 2 (6)
2020	+ 71 (2,843)	+ 1 (14)	+ 0 (1,793)	+ 0 (6)
2021	+ 99 (2,942)	+ 1 (15)	+ 0 (1,793)	+ 0 (6)

The attachment is being provided in a separate file in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors'
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Question No. 1.64

Responding Witness: Stuart A. Wilson

Q-1.64. Please provide the assumed line loss rate used for purposes of the Electric Sales and & Demand Forecast. Please include an explanation of the source for that assumed line loss rate. If available, please also provide a line loss rate for each hour of the year, along with supporting workpapers (in machine readable and unprotected format, with formulas intact).

A-1.64. The assumed annual line loss rate is 6.2% for KU and 5.8% for LG&E. Refer to the IRP, Volume II, Section 3, Table 1 for the source of this data. Hourly line loss rates are not available.

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Question No. 1.65

Responding Witness: Stuart A. Wilson

Q-1.65. Provide the Companies' hourly energy forecast referenced on page 5-7 in electronic, spreadsheet format.

A-1.65. See attachment to the response to SREA 1-6b.

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Question No. 1.66

Responding Witness: Charles R. Schram / Stuart A. Wilson

Q-1.66. Are the FERC-wholesale sales referenced on page 5-8, requirements or non-requirements sales? If both, please provide the breakdown of each.

A-1.66. The wholesale contracts are partial-requirements and the forecast reflects sales. See the response to PSC 1-28.

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Question No. 1.67

Responding Witness: Stuart A. Wilson

Q-1.67. Please provide, in spreadsheet format, the input and output files produced in the development of the Companies energy requirements and peak forecasts.

A-1.67. See attachments to the response to Question No. 3. All input and output files related to the energy requirements forecast are located in this folder: *Electric_Load_Forecast\4_Demand_Forecasts\1_Hourly_Demand\Load_Duration_Curve.*

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Question No. 1.68

Responding Witness: Stuart A. Wilson

Q-1.68. Please provide a spreadsheet showing the specific post estimation adjustments, if any, made to the Companies energy requirements and peak forecasts.

A-1.68. See attachments to the response to Question No. 3 and the first two tabs in the following file: *Electric_Load_Forecast\4_Demand_Forecasts\1_Hourly_Demand\Load_Duration_Curve\Data\ CONFIDENTIAL_HourlyDemandForecastInputs_OvernightCharging_2022BP_D2.xlsx*.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Case No. 2021-00393

Question No. 1.69

Responding Witness: Stuart A. Wilson

Q-1.69. Please refer to the discussion of the high and low energy requirements forecast on page 5-34 of the IRP. Please explain how the Companies developed the 180 MW industrial customer load growth or load loss.

A-1.69. See the response to PSC 1-19a.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors' Initial Request for Information
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Question No. 1.70

Responding Witness: Stuart A. Wilson

Q-1.70. Please explain how existing DSM programs were incorporated into the load forecast. I.e. were savings from historical programs added back to the load forecast to get a "no DSM" forecast or was a DSM variable included as an independent variable in the regression model?

A-1.70. See the response to PSC 1-13a.

LOUISVILLE GAS AND ELECTRIC COMPANY
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Response to Joint Intervenors' Initial Request for Information Dated January 21, 2022

Case No. 2021-00393

Question No. 1.71

Responding Witness: Stuart A. Wilson

Q-1.71. Please explain how the Companies incorporated future DSM savings into the energy requirements forecasts.

A-1.71. Energy requirements are the sum of sales and losses. DSM savings are included in the sales forecast. See the response to PSC 1-13a.

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Question No. 1.72

Responding Witness: Stuart A. Wilson

Q-1.72. Please provide the summer and winter capacity contribution assumptions modeled for distributed generation.

A-1.72. Summer and winter capacity contribution assumptions are utilized in resource planning as the assumed output (on average over a range of peak weather conditions) for non-dispatchable resources during the summer and winter peak. Because the cost of residential solar is higher than utility scale solar (see Table 5 on page 10 of the Resource Screening Analysis), residential solar was not evaluated in the Companies' Long-Term Resource Planning Analysis and the IRP did not contemplate summer and winter capacity contributions for residential solar.

See Volume II, section 5.2, pages 15-16 for a summary of the way increasing distributed generation is reflected in the hourly energy requirements forecast. The Companies develop an hourly energy requirements forecast with no distributed generation and then layer on the impact of distributed generation by subtracting an hourly distributed generation forecast that is correlated with weather in the load forecast. Like utility-scale solar, the forecasted contributions to peak for distributed solar generation varies over the forecast period from one year to the next.

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Question No. 1.73

Responding Witness: David S. Sinclair

Q-1.73. Refer to Vol. I at 8-34, regarding the Companies' "Carbon Capture Research."

a. Is there an operational carbon capture system at any existing natural gas plant in the country? If so, please identify each such plant, including the following details to the extent known:
   i. Location, owner, and operator;
   ii. Estimated or actual capital cost for the plant;
   iii. Estimated or actual capital cost for the CCS component;
   iv. Estimated or actual O&M costs for each of the plant and the CCS component; and
   v. Estimated or actual operating costs for each of the plant and the CCS component.

b. Please describe in detail the "challenges of carbon capture at natural gas plants," including identification of supporting documentation.

c. What volume of gas can be processed on (i) an hourly, (ii) daily, (iii) monthly, and (iv) yearly basis by the installed carbon capture slip-stream pilot demonstration system at the E.W. Brown plant?

d. The Carbon Capture Research paragraph on page 8-34 includes the statement that "[t]he post-combustion process takes a small portion of the flue gas and uses an amine-based solvent to capture carbon dioxide." Please quantify the "small portion of the flue gas" discussed in that statement.

e. How much carbon dioxide has been captured to-date by the carbon capture slip-stream pilot demonstration system at the E.W. Brown plant?

A-1.73.

a. According to the International Energy Agency's "CCUS in Power" report from November 2021, there is not an operational carbon capture system at an existing natural gas power plant in the United States.[21]

b. Some of the challenges of carbon capture at natural gas plants relative to coal include lower carbon dioxide concentration in the flue gas.[22] Flue gas from a natural gas combined cycle (NGCC) plant contains approximately 4% carbon dioxide by volume—a typical coal plant has 12-15% carbon dioxide by volume in the flue gas—which provides less driving force for separating the carbon dioxide form the rest of the flue gas to the capture liquid.[23] Although there is lower carbon density in natural gas flue gas, the overall process is cheaper because there is less total carbon dioxide mass to be captured and stored.

c. The local density of flue gas is approximate 0.067 lb/ft^3, and the local density of the carbon dioxide is approximately 0.103 lb/ft^3. The capture efficiency is 90% for most of time with 14 vol% carbon dioxide content in the flue gas. Since emissions rates are typically measured and expressed on a mass basis, the Companies have provided mass carbon dioxide emissions as well.[24]

(i) Capture Rates per Hour			
Flue Gas	Volume	78,000	Cubic Feet
Flue Gas	Mass	2.61	Tons
Carbon Dioxide	Volume	9,828	Cubic Feet
Carbon Dioxide	Mass	0.51	Tons
(ii) Capture Rates per 24-Hour Day			
Flue Gas	Volume	1,872,000	Cubic Feet
Flue Gas	Mass	63	Tons
Carbon Dioxide	Volume	235,872	Cubic Feet
Carbon Dioxide	Mass	12	Tons
(iii) Capture Rates per 730-Hour Month			
Flue Gas	Volume	56,940,000	Cubic Feet
Flue Gas	Mass	1,907	Tons
Carbon Dioxide	Volume	7,174,440	Cubic Feet
Carbon Dioxide	Mass	369	Tons
(iv) Capture Rates per Year Assuming 8760 Hours			
Flue Gas	Volume	683,280,000	Cubic Feet
Flue Gas	Mass	22,890	Tons
Carbon Dioxide	Volume	86,093,280	Cubic Feet
Carbon Dioxide	Mass	4,434	Tons

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[21] IEA https://www.iea.org/reports/ccus-in-power

[22] Department of Energy https://www.energy.gov/sites/prod/files/2016/09/f33/DOE - Carbon Capture Utilization and Storage_2016-09-07.pdf

[23] National Energy Technology Laboratory https://netl.doe.gov/coal/carbon-capture/post-combustion

[24] Frimpong, Reynolds A., Heather Nikolic, David Bahr, Gopi Kiran, and Kunlei Liu. "Pilot scale testing of an advanced solvent in a 0.7 MWe post-combustion CO2 capture unit." International Journal of Greenhouse Gas Control 106 (2021): 103290. https://doi.org/10.1016/j.ijggc.2021.103290

d. The unit captures 0.7 MW equivalent of flue gas at 78,000 cubic feet, or 2.61 tons, per hour. In terms of carbon dioxide, the unit captures 9,828 cubic feet, or 0.51 tons, per hour.

e. Approximately 3,060 tons of carbon dioxide has been captured. The capture rate of this small pilot is 0.51 tons per hour and the unit has operated approximately 6,000 hours.

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Question No. 1.74

Responding Witness: Stuart A. Wilson

Q-1.74. If Astrape provided the Companies with a study summarizing its SERVM modeling on their behalf, please provide a copy of that study.

A.1.74. Astrape has not provided such a study.

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Question No. 1.75

Responding Witness: Stuart A. Wilson

Q-1.75. In reference to Figure 5-6, please answer the following:

a. What is meant by the inclusion of "Reliability" in the name "Reliability & Production Cost" that is not normally captured by the term "Production Cost"?

b. Why does Reliability & Production Cost go down while Capacity Cost goes up?

c. Why is the shape of Reliability & Production Cost asymptotic while Capacity Cost is linear?

d. How do the Companies distinguish, if at all, between an Economic Reserve Margin and a traditional Planning Reserve Margin?

e. Why, in the Companies' judgement, would it be reasonable to include that Total Cost decline and then increase?

f. Doesn't the portion of the graph in which Total Cost decreases while Capital Cost increases and Reliability & Production Cost decrease imply that Reliability & Production Cost is decreasing at a faster rate than Capital Cost is increasing? If not, why not? If so, why do the Companies believe this is a reasonable assumption?

g. Doesn't the portion of the graph in which Total Cost increases while Capital Cost increases and Reliability & Production Cost decrease imply that Reliability & Production Cost is decreasing at a slower rate than Capital Cost is increasing? If not, why not? If so, why do the Companies believe this is a reasonable assumption?

h. Why does the minimum of the Total Cost line correspond with the point at which Reliability & Production Cost intersects with Capacity Cost?

A.1.75.

a. Reliability costs result from generation shortages and comprise the assumed cost to customers of unserved energy and the cost of power purchases that exceed the Companies' marginal generation cost. Production costs include the Companies' generation cost (fuel and variable O&M) and the cost of other power purchases.

b. As capacity is added, fixed capacity costs and reserve margin increase. At the same time, reliability and generation production costs decrease because the likelihood of a generation shortage decreases, resulting in lower cost to customers of unserved energy and lower cost of expensive power purchases.

c. The capacity cost line is linear because the incremental cost of adding new capacity is assumed to be constant. On the other hand, the reliability and production cost line is nonlinear because the incremental value of adding new capacity (measured by reduction in reliability & production cost) decreases as more capacity is added to the generation portfolio. At extremely high reserve margins, adding new capacity will have no impact on reliability and production costs.

d. Economic reserve margin is the reserve margin for the generation portfolio where the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized. In North America, the most commonly used physical reliability guideline is the 1-in-10 loss-of-load event ("1-in-10 LOLE") guideline. Systems that adhere to this guideline are designed such that the probability of a loss-of-load event is one event in ten years. In addition to the economic reserve margin, the reserve margin analysis considers the resources needed to meet this guideline. The reserve margin that meets the 1-in-10 LOLE guideline does not necessarily coincide with the economically optimal reserve margin.

e. The shape of total cost is the result of increasing capacity cost and decreasing reliability and production cost. At lower reserve margin, capacity cost is low but reliability and production cost is high. At higher reserve margin, capacity cost is high but reliability and production cost is low. It is reasonable to use economic reserve margin to determine a generation portfolio that minimizes the sum of those two costs.

f. Figure 5-6 is for illustrative purpose only. The Companies did not make any assumptions for the rate of changes.

g. See the response to part (f).

h. The minimum of total cost is not related to the intersection of capacity cost and reliability and production cost. Depending on the relationship between those two costs, the minimum of total cost can occur anywhere in the range of reserve margins.

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Question No. 1.76

Responding Witness: Stuart A. Wilson

Q-1.76. Regarding the SERVM modeling discussed at pdf page 47 of Volume III please answer the following:

a. How many iterations (draws) were performed in this study?

b. What was the relationship between weather years sampled for load and those sampled for renewables?

c. What forced outage rates were assumed?

d. What "unit availability" assumptions were used?

e. How, if at all, was convergence determined? Please provide any documentation in electronic workbook(s) with all formulas and links intact that show your work.

A.1.76.

a. For each generation portfolio, 300 iterations of random drawing were performed for each of the 48 hourly demand forecasts.

b. There was no sampling for weather year based load forecasts. All 48 weather year based load forecasts were used with equal probability. Also, there was no sampling for renewables.

c. See Table 3 on page 14 of the Reserve Margin Analysis.

d. See the response to part (c).

e. No convergence criteria was specified. All 300 iterations were performed for each weather year load forecast, and the result for each weather year was computed as the average of the 300 iterations.

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Question No. 1.77

Responding Witness: Stuart A. Wilson

Q-1.77. With regards to the Equivalent Load Duration Curve Model, please answer the following:

a. Who licenses and maintains the model?

b. Please provide a user guide for the model.

c. Does the model represent time using load duration curves? If so, why do the Companies believe this is a reasonable approach for purposes of evaluating reliability?

d. How, if at all, was convergence determined? Please provide any documentation in electronic workbook(s) with all formulas and links intact that show your work.

A.1.77.

a. The Companies create and maintain the model.

b. The Companies developed the model internally. Therefore, although there is no official user guide, the Companies based the development of the model on pages 213-224 in Expansion Planning for Electrical Generating Systems: A Guidebook, International Atomic Energy Agency, Vienna, 1984.[25]

c. Yes, load duration curves are used. The Companies believe that this is a reasonable approach because: (1) this approach has been used in the electric power industry for many decades (see the response to part b.); (2) the Companies have compared the results from this approach to other models' results and they are consistent; and (3) this approach is able to consider a more complete range of unit availability scenarios.

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[25] Available online at https://www-pub.iaea.org/MTCD/publications/PDF/TRS1/TRS241_Web.pdf.

d. The concept of convergence is not applicable for the Equivalent Load Duration Curve Model.

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Question No. 1.78

Responding Witness: Stuart A. Wilson

Q-1.78. Please refer to page 5-15 of the IRP where it states that "The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM")" in the discussion of the reserve margin analysis.

a. Please provide the input and output modeling files, in spreadsheet format, with all formulas and links intact for the ELDCM and SERVM models.

b. Please confirm if the Companies put the capacity expansion plans from the modeling for this IRP back into SERVM to confirm that the plans met the Companies' reliability criteria. If this step was completed, please provide the results for each of the capacity expansion plans developed for this IRP.

c. Are the reserve margin requirements developed out of these studies installed capacity (ICAP) or unforced capacity (UCAP) requirements? If ICAP, why do Companies' use this metric rather than UCAP?

A.1.78.

a. See the response to Question No. 3. The files are located at the following file path: \0283_2021IRP\ReserveMargin.

b. The Companies did not put the capacity expansion plans back into SERVM. The capacity expansion plans were optimized to meet minimum reserve margin requirements determined by ELDCM and SERVM.

c. ICAP was used in ELDCM and SERVM because forced outage rates are also inputs in those models.

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Question No. 1.79

Responding Witness: Stuart A. Wilson

Q-1.79. Please refer to page 4 of the 2021 IRP Reserve Margin analysis that says "Therefore, the Companies' target reserve margin range is 17 to 24 percent in the summer and 26 to 35 percent in the winter." Please give the summer and winter reserve margin constraints used within Plexos for the capacity expansion modeling.

Q.1.79. The Companies used the minimums of the 2021 IRP's seasonal target reserve margin ranges, which are 17 percent for summer and 26 percent for winter.

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Question No. 1.80

Responding Witness: Stuart A. Wilson

Q-1.80. In the 2021 IRP Reserve Margin Analysis, "Table 7 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2019 and 2020 and the winter months of 2020 and 2021."

a. Please provide the workpaper underlying Table 7 ("Daily ATC") of the 2021 IRP Reserve Margin Analysis with formulae intact.

b. Please provide the specific dates represented in Table 7.

c. Please provide the available transmission capacity values shown in Table 7 disaggregated to reflect each neighboring region on an independent basis.

d. Among the dates represented in Table 7 and for each Daily ATC Range provided in the first column of Table 7, please specify the percentage of days when export capability of a neighboring system was greater than the Companies' import capability.

e. Among the dates represented in Table 7 and for each Daily ATC Range provided in the first column of Table 7, please specify the percentage of days when export capability of a neighboring system was less than the Companies' import capability.

f. Please explain why only weekdays were considered in Table 7's representation of Daily ATC.

g. Please provide the daily ATC between the Companies' system and neighboring regions from January 1, 2019, through December 31, 2021.

A-1.80.

a. See attachment being provided in Excel format.

b. See the response to a.

c. See the response to a.

d. The table below shows the percentage of days when the sum of export capability of the neighboring regions was greater than the Companies' import capability.

Daily ATC Range	Percentage
0	87%
1-199	100%
200-399	90%
400-599	76%
600-799	91%
800-999	52%
>=1000	66%

e. The table below shows the percentage of days when the sum of export capability of the neighboring regions was less than the Companies' import capability.

Daily ATC Range	Percentage
0	13%
1-199	0%
200-399	10%
400-599	24%
600-799	9%
800-999	48%
>=1000	34%

f. The reserve margin analysis focuses on the days when the Companies' load is high and the ATC is limited, which typically occurs on weekdays.

g. This data was not used in the IRP and is not readily available. For the ATC data that was used in the IRP, see the response to part (a).

The attachment is being provided in a separate file in Excel format.

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Question No. 1.81

Responding Witness: Stuart A. Wilson

Q-1.81. Refer to the following statements from page 17 of the 2021 IRP Reserve Margin Analysis: "During peak hours when ATC is most likely needed to ensure reliable supply, ATC in ELDCM and SERVM is assumed to be approximately 500 MW two-thirds of the time and zero MW one-third of the time. Alternative ATC scenarios are also considered to understand the impact of this input assumption on the analysis.

a. Please define each of the alternative ATC scenarios also considered.

b. For each alternative ATC scenario defined in response to subpart (b), please explain the empirical basis for each alternative, including analysis, calculations, or supporting documentation, if any.

Q-1.81.

a. The Companies considered the scenarios of 0 and 1,000 MW of ATC during peak hours.

b. 0 MW in the low case reflects a scenario where the Companies have no access to power in neighboring regions. 1,000 MW was chosen as a proxy for 'high" case scenario, representing twice as much as the base case scenario.

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Question No. 1.82

Responding Witness: Stuart A. Wilson

Q-1.82. Please clarify the source of the new SCCT capacity reported in Table 11 of the 2021 IRP Reserve Margin Analysis: Page 20 of the 2021 IRP Reserve Margin Analysis states that "[t]he cost of new SCCT capacity is taken from the 2021 IRP Resource Screening Analysis and is summarized in Table 11 in 2025 dollars," but Footnote 23 of the same document states that Table 11 reflects costs from NREL's 2018 ATB.

A-1.82 Footnote 23 is incorrect. NREL's 2021 ATB was the data source for Table 11.

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Question No. 1.83

Responding Witness: John Bevington / Stuart A. Wilson

Q-1.83. Refer to Vol. III, 2021 Reserve Margin Analysis at page 22, which states that, "The peak demand forecast is the forecast of peak demand under normal weather conditions. The impact of the Companies' DSM programs is reflected in the Companies' peak demand forecast."

a. Please identify the specific DSM programs and program years assumed to be reflected in the referenced peak demand forecast

b. Please explain in full the manner in which the impact of future DSM programs was accounted for in the Companies' peak demand forecast.

A-1.83.

a. The Companies' current DSM programs are:

Nonresidential Rebates Program
WeCare Program
Residential and Small Nonresidential Demand Conservation Program
Large Nonresidential Demand Conservation Program
Marketplace - Appliances

The DSM program years are 2019-2025.

b. See the response to PSC 1-13a.

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Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1.84

Responding Witness: Stuart A. Wilson

Q-1.84. Refer to Vol. III, 2021 Reserve Margin Analysis at Tables 13–16.

a. Please list and specify the timing of each resource addition and retirement assumed in each of the Generation Portfolios.

b. Was SERVM used to evaluate the impact of adding 260 MW of nameplate solar to the generation portfolio, as modeled with ELDCM? If so, please provide that the reserve margin analysis results with new solar from SERVM. If not, please explain in full why the Companies did not use SERVM to evaluate the impact of new solar.

A-1.84.

a. Because the study year for the reserve margin analysis is 2025, the timing of each resource addition and retirement is assumed in 2025.

b. SERVM was not used to evaluate the impact of adding 260 MW of solar because (1) ELDCM and SERVM produce similar results and (2) SERVM requires a much longer run time.