COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

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

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY AND
KENTUCKY UTILITIES COMPANY TO
SOUTHERN RENEWABLE ENERGY ASSOCIATION'S
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

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 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

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.

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 Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 1

Responding Witness: Stuart A. Wilson

Q-1. Provide complete and unredacted copies of the following materials used or relied upon by the Companies in their 2021 IRP. For each Table below, provide a live, executable (i.e., Excel) version.

a. IHS Markit, "Executive Summary: US Economic Outlook" (May 2021), referenced on PDF p. 2 of 18 of IRP Volume II.

b. "Table 5-5: Coal and Natural Gas Prices (Nominal $/mmBtu)," Volume I.

c. Transmission expansion plan projects, Volume III, PDF p. 82 of 140.

d. Transmission system map, Volume III, PDF p. 83 of 140.

e. "Table 4: 2025 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)," Volume III, PDF p. 38 of 140.

f. "Table 5: 2025 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)," Volume III, PDF p. 38 of 140.

g. "Table 6: Interruptible Contracts," Volume III, PDF p. 39 of 140.

h. "Table 8-7: Cost of Fuel ($/MMBtu)," Volume I, PDF p. 91 of 118.

i. "Table 8-9: Production Costs," Volume I, PDF p. 92 of 118.

j. The results of the Companies' recent resource RFP (https://lge-ku.com/lge-ku-request-proposals-sell-electric-capacity-energy). For each project proposal, identify the size (megawatts), the cost (e.g., the $/MWh and/or $/MW-year bid), the resource type, whether the project was a build-transfer or power purchase agreement. Provide any analysis the Companies conducted on the proposals submitted under this RFP, and the conclusions the Companies reached as a result of this RFP. Identify each project selected under this RFP and when the anticipated commercial operation date is of each project.

A-1.

a. The Companies filed the requested confidential information as part of their initial IRP filing and provided SREA's counsel access to it on January 19, 2022.

b. The Companies filed the requested confidential information as part of their initial IRP filing and provided SREA's counsel access to it on January 19, 2022. The Companies are providing the Excel version of the requested table subject to the petition for confidential protection the Companies filed regarding this information on October 19, 2021.

c. See the response to part (a).

d. See the response to part (a).

e. See the response to part (b).

f. See the response to part (b).

g. See the response to part (b).

h. See the response to part (b).

i. See the response to part (b).

j. The Companies did not use or rely upon any RFP responses in their 2021 IRP.

The attachment for Question 1(b) is being provided in a separate file in Excel format

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 2

Responding Witness: Stuart A. Wilson

Q-2. Provide live, executable (i.e., Excel) versions of the following Tables and Figures:

a. Figure 5-4
b. Figure 5-16
c. Figure 5-10
d. Figure 5-20
e. Figure 5-21
f. Figure 5-22
g. Table 5-13
h. Table 5-14
i. Table 5-18
j. Table 6-5
k. Table 6-6
l. Table 7-1
m. Table 7-2
n. Table 7-3
o. Table 7-4
p. Table 8-3
q. Table 8-4
r. Table 8-5
s. Table 8-6
t. Table 8-15
u. Table 8-16
v. Table 8-17
w. Table 8-18

A-2. See attachment being provided in Excel format. Figure 5-4 was created in R and cannot be replicated in Excel due to the amount of data used in its creation.

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

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 3

Responding Witness: Stuart A. Wilson

Q-3. Provide live, executable (i.e., Excel) versions of the Companies' complete analysis that produced the results shown in "Table 4: LCOE of SCCT and 4-Hour Battery Storage ($/MWh)" in Volume III, PDF p. 18 of 140. Identify any assumptions used in this analysis that are not already described in Volume III, PDF pp. 17-19 of 140.

A-3. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachment is Confidential and provided separately under seal in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 4

Responding Witness: David S. Sinclair

Q-4. Reference the Companies' 2021 integrated resource plan (IRP) stakeholder engagement process.

a. Describe the Companies' outreach to stakeholders and stakeholder engagement process with respect to developing their 2021 IRP.

b. To the extent it is not fully discussed in (a), describe and explain how the Companies solicited input and feedback on key components related to their IRP from relevant entities or stakeholders during the Companies' process of developing their 2021 IRP.

c. Identify which external entities or stakeholders the Companies have been in communication with regarding the development of their IRP, how the Companies have communicated with these external entities or stakeholders, the frequency of these communications, and the topics and issues discussed with each of these entities or stakeholders.

d. Identify the number of public meetings, open houses, technical conferences, and/or workshops the Companies held on the development of their 2021 IRP prior to filing their 2021 IRP.

   i. Provide all materials that were disseminated by the Companies and participating entities or stakeholders related to these meetings, including any handouts, presentations, agendas, and meeting notes.

   ii. If the Companies did not conduct any public meetings, open houses, technical conferences, and/or workshops as part of their process to develop their 2021 IRP, explain why they did not do so.

e. Identify the number of, location of, and topics discussed at each meeting, call, or workshop the Companies held with external entities or stakeholders regarding the development of their 2021 IRP that were not public.

i. Provide all materials that were disseminated by the Companies and participating entities or stakeholders related to these meetings, including any handouts, presentations, agendas, and meeting notes.

A-4.

a. The Companies did not have a 2021 IRP stakeholder engagement process and have not had such a pre-filing process for any previous IRP. Unlike demand-side management plan filings for which there is a statutory requirement to consider the involvement of "customer representatives and the Office of the Attorney … in developing the plan,"[1] the Commission's IRP regulation neither requires nor contemplates a pre-filing stakeholder process.[2] Rather, the IRP regulation provides a process by which the Commission Staff and intervenors may issue discovery requests and submit comments about an IRP *after* a utility files it.[3] Likewise, the Commission may schedule conferences to discuss an IRP *after* a utility files it.[4] But the regulation does not require or even suggest a pre-filing public or stakeholder process.

b. As discussed on page 5-8 of Volume 1, the Companies develop their electricity sales forecasts with specific intelligence on the prospective energy requirements of the Companies' largest customers. This information is gathered through direct communications with these customers for the purpose of improving the accuracy of the sales forecast.

c. See attached. The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection. The Companies discuss these customers' sales and demand forecasts once per year primarily via email.

d. See the response to part (a).

    i. N/A

    ii. See the response to part (a).

e. See the response to part (c).

    i. See the response to JI 1-3. The requested information is included in the following folder:

[1] KRS 278.285(1)(f).
[2] 807 KAR 5:058.
[3] *See, e.g.,* 807 KAR 5:058 Sec. 11(1).
[4] *See, e.g.,* 807 KAR 5:058 Sec. 11(2).

Electric_Load_Forecast\2_Forecasts\Major_Accounts\Send_to_MA
The information requested is confidential and proprietary and is being provided under seal pursuant to a petition for confidential protection.

The entire attachments for 4(c) and 4(e)(i) are Confidential and provided separately under seal

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 5

Responding Witness: Stuart A. Wilson

Q-5. Identify each generating unit that was designated as a must-run unit in the Companies' IRP modeling "Base Energy Requirements, Base Fuel" case and for each year such a designation or requirement was imposed on the unit. For this question, "must-run" means the IRP modeling assumed the unit would continue to run (e.g., regardless of cost), and/or the modeling did not allow the unit to be economically retired in one or more years of the IRP period. For each such unit, explain why this designation or requirement was imposed.

A-5. 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 in all years in which these units are online. Specific to renewable PPAs and OVEC, the Companies have made or will have made obligations to third parties regarding energy procurement, which warrants "must-run" designation.

Unit retirements are specified in Table 1 of the Long-Term Resource Planning Analysis in Vol. III of the IRP and are fixed as a simplifying assumption in the 2021 IRP analysis. The analysis did not consider scenarios where units retired earlier or later than the specified years.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 6

Responding Witness: Stuart A. Wilson

Q-6. Reference the Companies' load forecast in their 2021 IRP.

a. Explain the "specific intelligence on the prospective energy requirements of the utilities' largest customers" (IRP, p. 5-8) that the Companies have in their possession and how that intelligence was factored into the Companies' industrial sales growth forecast.

b. Provide an executable version of the Company-wide (the combined entities) hourly load profile for the historical year 2020 (or the most recent available calendar year if 2020 is not available) and for each future year in the IRP period (i.e., 2022 through 2036).

A-6.

a. See the response to Question No. 4b as well as Volume II, Section 4.2, page 8. Information for these customers may include maintenance schedules, usage estimates for new equipment or production changes, and planned energy efficiency projects. This information for each customer is evaluated by the Companies and used to update the customer's forecast if needed.

b. 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 Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 7

Responding Witness: Stuart A. Wilson

Q-7. Reference the supply-side resources considered by the Companies in their 2021 IRP.

a. Explain whether and to what extent the Companies included the cost reductions associated with batteries paired with solar due to these battery systems being eligible to take the federal investment tax credit (subject to limitations on the battery charging from solar)?

b. Describe how the Companies evaluated and modeled utility-scale solar paired with battery energy storage facilities as a distinct resource (i.e., distinguishable from solar-only or battery-only resources).

   i. In addition, explain what the primary reasons are that the Companies did not select to procure this resource in the base load, base fuel price case (1) in the near term (over the next 1-3 years); (2) in the medium term (through 2024-2030); and (3) in the long-term (2031 and thereafter).

c. Reference Volume 1, p. 5-43, stating in pertinent part that "In the base load, base fuel price case, peaking resources are primarily used to meet peak load needs and operate at low capacity factors." For each generating unit included in the 2021 IRP, provide an executable version (i.e., Excel file) of the capacity factor used by the Companies for each year of the IRP. Provide the same for each of the other scenarios included in the 2021 IRP.

d. What do the Companies forecast or expect the annual and seasonal (e.g., summer, winter) capacity factors will be for the new natural gas combustion turbines in plans to procure under their 2021 IRP for each year of the IRP planning horizon?

e. Identify the assumed or expected life (i.e., number of years) of a new natural gas combustion turbine that the Companies use when analyzing new resource options. Explain whether this assumption is different than the assumed life used by the Companies for ratemaking purposes, and if so, how it is different.

f. Reference Volume III, PDF p. 20 of 140. Explain why wind resources in both Kentucky and Indiana were considered in the 2021 IRP, but wind resources located in other states (e.g., other MISO states) were not considered as a potential resource and was not modeled in this IRP?

A-7.

a. In their Long-Term Resource Planning Analysis, the Companies assumed that a 26% investment tax credit ("ITC") would be applicable for batteries by the end of the IRP study period regardless of the battery's charging source. With this assumption, the Companies evaluated battery storage in a favorable light and obviated the need to the model charging restrictions associated with pairing a battery only with solar. Therefore, the Companies did not model solar paired with battery storage as a distinct resource but instead, modeled these resources separately.

b. See the response to part (a).

   i. See the response to part (a). Even with favorable cost assumptions and no charging restrictions for battery storage, the least-cost generation portfolio in the base load, base fuel case favors simple-cycle combustion turbines ("SCCTs") over battery storage for peaking capacity. Compared to the cost of adding SCCT to an existing site, the cost of battery storage with the ITC does not become competitive until late in the analysis period where battery storage capital costs are projected by NREL to be 23% lower and SCCT capital costs are projected to be 10% higher.

   The Companies plan their generation portfolio to serve a system load at the lowest reasonable cost. In this context, batteries have the most value if they can be charged when the portfolio's marginal cost is lowest (i.e., during nighttime hours on most days). Because solar produces energy during the day, solar is not an ideal resource for charging a battery. Furthermore, pairing a battery with an intermittent resource reduces the value of the battery because it reduces the likelihood that the battery will be charged when needed.

c. See attachment being provided in Excel format. The attachment includes capacity factors for the base load, base fuel case. The Companies did not develop detailed production cost forecasts for the other scenarios in the IRP. The Companies note that for purposes of displaying data in this table, modeled capacity factors for like units are averaged together to more closely reflect how the Companies would elect unit commitment and dispatch.

d. See the table below. The underlying load forecast assumes normal weather, so actual seasonal capacity factors may vary during seasonal extremes.

Year	Annual Capacity Factor	Summer Capacity Factor	Winter Capacity Factor
2028	20%	31%	6%
2029	22%	32%	8%
2030	21%	30%	12%
2031	20%	29%	7%
2032	18%	28%	6%
2033	19%	27%	6%
2034	21%	31%	14%
2035	23%	29%	15%
2036	21%	23%	15%

e. The Companies assume the expected life of a new natural gas combustion turbine is 30 years. This would be the same assumption used for ratemaking purposes.

f. The wind resource located in Indiana was a proxy for out-of-state wind as a simplification in the IRP analysis. Prior to implementation, this plan will be assessed against other market available alternatives. That process will welcome wind proposals from any state.

The attachment for Question 7(c) is being provided in a separate file in Excel format

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 8

Responding Witness: Stuart A. Wilson

Q-8. Reference the Companies' reserve margin analysis.

a. Reference PDF p. 36 of 140 of Volume III, stating in pertinent part that "A key aspect in developing a target reserve margin is properly considering the likelihood of unit outages during extreme weather events." To what extent did the Companies' modeling consider the possibility of correlated unforced outages across their generating units during extreme weather events? Provide any analysis the Companies conducted to analyze this issue and describe how the results and conclusions were factored into the Companies' 2021 IRP.

A-8.

a. Because unforced (i.e., planned maintenance) outages typically occur in the spring and fall when the Companies' load is generally lower relative to the winter and summer, they were not considered in the reserve margin analysis. The Companies plan maintenance outages so they will not have a material impact on reliability. Instead, the Companies' analysis considers a complete range of forced (i.e., unplanned) unit outages. This includes analyzing outage scenarios where multiple units are unavailable at the same time, though forced unit outages are not assumed to be correlated.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 9

Responding Witness: Stuart A. Wilson

Q-9. Reference the Companies' transmission system.

a. Reference Volume III, PDF p. 39 of 140. Provide an executable version of the underlying analysis or analyses used as the basis for "Table 7. Daily ATC" and to support the statement "Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 42% of the time."

b. Reference Volume III PDF p. 39 of 140. Identify the Available Transmission Capacity for the Companies for each hour during calendar years 2019, 2020, and 2021.

A-9.

a. See attachment being provided in Excel format.

b. The Companies do not have the requested hourly data.

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

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 10

Responding Witness: Stuart A. Wilson

Q-10. Reference the Companies' generating unit retirement analysis.

a. Reference Table 10 in Volume III, which identifies stay-open costs for coal units that are 40 or more years old and peaking units 15 or more years old. Identify the "Stay-Open Cost ($/kW-year)," "Average Energy Cost ($/MWh)," and "Stay-Open Costs + Average Energy Costs ($/MWh)" for each unit owned and / or operated by the Companies that is not already included in Table 10. If the Companies have not performed or are unable to perform such an analysis, explain why.

b. Explain the extent to which the Companies considered retiring any coal units that are 40 or less years old, or peaking units 15 or less years old as part of their IRP and provide any analysis the Companies conducted as part of this consideration. If the Companies did not consider or analyze this topic, explain why not.

A-10.

a. The following table shows stay-open costs and average energy costs for the Companies' generation units that are not included in Table 10. Note that Mill Creek 1 and the Companies' small-frame SCCTs are assumed to be retired by 2025. Therefore, they are excluded.

Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Ghent 4	90.8	24	43
Mill Creek 4	104.6	23	37
Trimble County 1	77.8	22	35
Trimble County 2	75.7	21	35
Cane Run 7	40.7	19	25

b. The Companies did not evaluate these retirements. The reserve margin analysis demonstrates that retiring higher cost units is not economically optimal. Therefore, an analysis of retiring lower cost units was not necessary.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 11

Responding Witness: Stuart A. Wilson

Q-11. Reference the Companies' discussion of electric vehicles (Volume I, beginning at PDF p. 36 of 118).

a. Provide a full explanation how the Companies integrated its forecast of EV adoption into their load forecast for its base, high, and low cases.

b. For each year of the IRP planning period, identify the hourly load profile assumed by the Companies that is from EV charging.

c. Provide a live, executable version of the Companies' workpapers that demonstrate how their forecast of increasing EV adoption impacts and is integrated into the Companies' load forecast during the IRP planning period.

d. For each year in the IRP planning period, identify the contribution of EV charging to the Companies' winter peak load. "Contribution" means the total MW of load associated with this end use during the Companies' forecasted winter peak.

A-11.

a. See the response to PSC 1-38 and the 2021 IRP, Volume II, Sections 4.6 and 5.2 for a discussion of the base EV forecast, which was used to develop the base and low load forecasts. For the high load forecast, the managed charging profile from the base EV forecast was scaled upward such that the assumed number of electric vehicles in the service territory was approximately equivalent to the number of EVs comprising 50% of new car sales by 2030.

b. See attachment being provided in Excel format. The Companies assume the managed charging profile for the base forecast, which is represented by columns E through G of the first tab of the attachment.

c. See the response to JI 1-67.

d. See table below:

Year	EV Contribution to Winter Peak in Base Load Forecast (MW)
2021	0
2022	0
2023	0
2024	0
2025	1
2026	1
2027	1
2028	1
2029	1
2030	5
2031	2
2032	2
2033	2
2034	3
2035	3
2036	11

The attachment for Question 11(b) is being provided in a separate file in Excel format

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 12

Responding Witness: Stuart A. Wilson

Q-12. Reference the Companies' discussion of space heating electrification (Volume I, beginning at PDF p. 39 of 118).

a. Provide a full explanation how the Companies integrated their forecast of space heating electrification into their load forecast for its base, high, and low cases.

b. For each year of the IRP planning period, identify the hourly load profile assumed by the Companies that is from space heating.

c. Provide a live, executable version of the Companies' workpapers that demonstrate how their forecast of space heating electrification impacts and is integrated into the Companies' load forecast during the IRP planning period.

d. For each year in the IRP planning period, identify the contribution of space heating to the Companies' winter peak load. "Contribution" means the total MW of load associated with this end use during the Companies' forecasted winter peak.

A-12.

a. Space heating and other end-uses are modeled in the base load forecast using a statistically-adjusted end-use model (see the response to PSC 1-40b). The assumed pace of space heating electrification in the base and low load forecasts is the same. In addition to the referenced section, see the response to PSC 1-19b for an explanation of space heating electrification in the high load forecast.

b. The Companies do not have a load profile that is specific to space heating.

c. See attachments to the response to JI 1-3. The following folder contains workpapers used to produce the Volume I figures and tables regarding space heating electrification:

Electric_Load_Forecast \6_IRP\Vol_I_Data\Space_Heating_Electrification

The following folder contains workpapers used to produce the high load forecast, which includes forecasting space heating electrification impacts: *Electric_Load_Forecast\6_IRP\Vol_I_Data\Scenarios\High_Scenario_File*.

d. The Companies do not have this information specifically for space heating. However, Figure 5-22 in Volume I shows the impact of higher space heating electrification on winter peak.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 13

Responding Witness: Daniel K. Arbough / David S. Sinclair

Q-13. Reference the Companies' share of the Ohio Valley Electric Corporation (OVEC) units.

a. Confirm or deny with complete explanation that the Companies' continued reliance on OVEC units to serve retail customers in Kentucky is congruent with a least-cost generation portfolio.

b. For each of the past 10 years, identify (1) the total megawatt-hours (MWh) generated by the OVEC units that represent the Companies' share, (2) the retail sales (MWh) to the Companies' customers from OVEC unit generation, (3) the off-system sales (MWh) generated by OVEC units.

c. For each of the past 10 years, identify (1) the total nominal costs associated the Companies' share of the OVEC units, and (2) the revenue associated with the sales from the Companies' share of the OVEC units.

d. Reference Table 10 in Volume III. For each OVEC unit, identify the "Stay-Open Cost ($/kW-year)," "Average Energy Cost ($/MWh)," and "Stay-Open Costs + Average Energy Costs ($/MWh)."

e. For each of the past 10 years, identify the annual capacity factor for each OVEC unit.

f. Identify the assumed retirement date of each OVEC unit.

g. Explain the impact of the U.S. Environmental Protection Agency's (EPA) proposal to deny the extension request for the Clifty Creek Power Station to continue using existing coal combustion residuals surface impoundments on the Companies' IRP and Companies' resource need in the coming decade, should the EPA's proposal be finalized and approved without modification. (Reference: "Proposed Denial of Alternative Closure Deadline for Clifty Creek Power Station", available at:

https://www.epa.gov/system/files/documents/2022-01/clifty_creek_proposed_decision-508_prepub.pdf)

h. Provide the most recent analysis the Companies have performed on the economics or the costs and benefits of continuing to utilize OVEC generating units to serve its Kentucky retail customers.

i. Provide the most recent analysis the Companies have performed on the viability of retiring the OVEC units at a date earlier than is currently assumed by the Companies in their 2021 IRP.

j. Describe any efforts the Companies are currently pursuing, or have made in the past three years, to engage in good faith efforts to manage existing OVEC contracts such as meaningful attempts to renegotiate contract provisions to ensure continued value for ratepayers or retire these units early.

A-13.

a. Confirmed. The Companies are each party to the longstanding Inter-Company Power Agreement ("ICPA") with OVEC, which expires in June 2040. An extension of the ICPA was approved by the Commission in 2011. The Companies' contractual obligations under the ICPA require them to pay their share of OVEC's fixed costs and to purchase at cost a minimum amount of energy based on the Companies' pro-rata ownership share of OVEC.[5] If the Companies were to simply stop scheduling energy from OVEC that was otherwise economic, meaning lower cost than other resources, then the cost of serving our customers would increase while the obligation to continue paying OVEC's fixed costs would remain. Such an approach would be incongruent with serving customers with a least-cost generation portfolio.

b. (1) See attached. The "Quantity" columns contain the energy purchased from OVEC by the Companies in kWh.
(2) There are no directly identifiable revenues associated with OVEC energy purchases.
(3) OVEC purchases are used only for native load.

c. (1) See attached. The "Amount" columns contain the costs in nominal dollars associated with the Companies' share of the OVEC units.
(2) There are not directly identifiable revenues associated with OVEC energy purchases.

d. The Companies do not have the requested data.

[5] The ICPA includes "minimum loading" provisions (set forth in Section 5.05 of the ICPA), requiring each Sponsor to either schedule delivery of its portion of OVEC's "total minimum generating output" or pay for any increased costs caused by failure to schedule and take its minimum output. These costs are assigned directly to the responsible Sponsor, rather than spread among all Sponsors.

e.

NCF	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Clifty Creek 1	59.0%	54.6%	58.7%	58.0%	43.1%	64.6%	64.9%	53.8%	44.8%	54.8%
Clifty Creek 2	46.5%	61.2%	62.2%	46.7%	52.8%	64.6%	59.4%	61.8%	44.4%	51.2%
Clifty Creek 3	59.9%	49.1%	34.9%	50.2%	51.3%	46.7%	68.2%	58.5%	40.6%	50.9%
Clifty Creek 4	53.1%	38.3%	65.8%	44.0%	48.5%	66.6%	60.7%	60.2%	45.7%	49.3%
Clifty Creek 5	55.5%	60.8%	68.0%	56.9%	45.8%	66.5%	63.4%	56.2%	45.2%	51.6%
Clifty Creek 6	56.0%	48.1%	50.9%	42.1%	43.8%	35.5%	45.6%	36.2%	28.4%	29.8%
Kyger Creek 1	42.7%	50.5%	68.3%	44.8%	56.8%	73.7%	74.7%	58.1%	55.9%	54.1%
Kyger Creek 2	52.0%	66.0%	55.4%	38.2%	52.7%	58.0%	73.9%	65.2%	55.8%	50.3%
Kyger Creek 3	57.9%	52.1%	56.7%	47.7%	57.9%	63.4%	62.7%	60.8%	47.4%	63.6%
Kyger Creek 4	50.2%	66.7%	63.0%	30.9%	56.8%	72.4%	61.1%	68.5%	51.9%	61.6%
Kyger Creek 5	58.6%	49.6%	68.8%	49.5%	58.0%	71.1%	60.5%	63.7%	55.0%	59.1%

f. The Companies do not assume retirement dates of the OVEC units. The Companies assume that they will stop purchasing power from OVEC in June 2040, when the ICPA expires.

g. Based upon information provided by OVEC management, the EPA's January 11th action represents a proposed conditional denial of OVEC's application for an alternative (extended) date to cease placement of CCR wastes and non-CCR wastewater and initiate closure activities for two surface impoundments at the Clifty Creek Station. The alternative dates OVEC requested are December 5, 2022 for one surface impoundment and April 2023 for the second surface impoundment. The proposed denial is subject to a public comment period running through late February, followed by an EPA final decision, which may occur during 2022. OVEC anticipates submitting information, potential design changes or both during the comment period to seek to address EPA concerns in the conditional denial, as well as considering legal strategies. In the event a final denial decision is issued without modification, that decision would not require the plant to shut down, it would only prohibit the continued placement of CCR and non-CCR wastewater into the surface impoundments through the alternative dates requested by OVEC. The conditional denial provides that Clifty Creek would be required to cease placing CCR in the impoundment 135 days after a final denial decision date. Clifty Creek would then be in a temporary outage until the new CCR treatment systems that are being installed to fulfill the requirements of the CCR rule are operational.

.

h. OVEC's continued operation is determined by its board. It is economic for the Companies to continue purchasing energy from OVEC, given the Companies' obligation to participate through 2040 in the ICPA, which was amended in 2010 and approved by the Kentucky Public Service Commission in Case Nos. 2011-00099 and 2011-00100. In addition, the Companies' share of OVEC was evaluated in the *2018 IRP Reserve Margin Analysis*, which is located in Volume III of the 2018 Integrated Resource Plan, which was filed in Case No. 2018-00348. See attached.

i. The Companies have not performed the requested analysis. See the response to part (h).

j. The Companies have always worked in good faith regarding OVEC matters. The Companies have worked with OVEC and its Sponsors concerning supporting OVEC's financial condition and third-party contractual rights, including participation in FirstEnergy Solutions bankruptcy and FERC legal proceedings and monitoring other OVEC-related legal proceedings or Sponsor credit matters, OVEC debt reserve structures, OVEC debt refinancings, OVEC operating efficiency and other cost-savings programs.

Louisville Gas and Electric Company/Kentucky Utilities Company
Case No. 2021-00393
OVEC Costs
For the Calendar Years 2010 through 2021

	Jan-10		Feb-10		Mar-10		Apr-10		May-10		Jun-10	
	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount
NL POWER PURCHASES - DEMAND	-	3,138,843.17	-	832,205.63	-	2,502,682.37	-	2,108,548.07	-	2,601,012.49	-	2,299,704.77
NL POWER PURCHASES - ENERGY	116,015,000	3,176,796.46	93,716,000	1,821,168.66	100,602,000	1,872,240.79	89,881,000	2,221,488.03	84,752,000	2,164,083.07	108,199,000	2,819,823.56
Grand Total	116,015,000	6,315,639.63	93,716,000	2,653,374.29	100,602,000	4,374,923.16	89,881,000	4,330,036.10	84,752,000	4,765,095.56	108,199,000	5,119,528.33
	Jan-11		Feb-11		Mar-11		Apr-11		May-11		Jun-11	
NL POWER PURCHASES - DEMAND	-	2,322,765.11	-	985,660.81	-	2,215,510.40	-	2,733,508.47	-	2,293,403.14	-	1,681,899.40
NL POWER PURCHASES - ENERGY	119,828,000	3,130,312.69	106,939,000	2,672,007.88	106,207,000	2,944,804.66	108,833,000	2,931,472.72	99,903,000	2,681,745.00	95,958,000	2,760,249.93
Grand Total	119,828,000	5,453,077.80	106,939,000	3,657,668.69	106,207,000	5,160,315.06	108,833,000	5,664,981.19	99,903,000	4,975,148.14	95,958,000	4,442,149.33
	Jan-12		Feb-12		Mar-12		Apr-12		May-12		Jun-12	
NL POWER PURCHASES - DEMAND	-	1,839,828.45	-	2,467,073.57	-	3,202,074.29	-	2,321,659.09	-	2,322,633.23	-	2,123,294.35
NL POWER PURCHASES - ENERGY	67,933,000	1,966,735.25	83,952,000	2,404,113.46	95,767,000	2,631,492.56	77,963,000	2,279,650.17	88,907,000	2,513,998.32	87,186,000	2,557,617.47
Grand Total	67,933,000	3,806,563.70	83,952,000	4,871,187.03	95,767,000	5,833,566.85	77,963,000	4,601,309.26	88,907,000	4,836,631.55	87,186,000	4,680,911.82
	Jan-13		Feb-13		Mar-13		Apr-13		May-13		Jun-13	
NL POWER PURCHASES - DEMAND	-	1,989,251.42	-	2,133,851.18	-	2,466,571.33	-	3,269,749.14	-	2,860,479.55	-	2,191,497.70
NL POWER PURCHASES - ENERGY	88,196,000	2,776,614.82	62,373,000	1,887,423.53	54,359,000	1,714,749.27	52,310,000	1,538,489.52	62,257,000	1,907,822.95	77,479,000	2,400,011.40
Grand Total	88,196,000	4,765,866.24	62,373,000	4,021,274.71	54,359,000	4,181,320.60	52,310,000	4,808,238.66	62,257,000	4,768,302.50	77,479,000	4,591,509.10
	Jan-14		Feb-14		Mar-14		Apr-14		May-14		Jun-14	
NL POWER PURCHASES - DEMAND	-	1,465,239.28	-	2,130,207.91	-	2,282,505.50	-	2,509,837.12	-	2,294,958.55	-	1,950,871.64
NL POWER PURCHASES - ENERGY	93,210,000	2,567,778.33	84,956,000	2,254,667.53	79,167,000	2,147,132.15	54,993,000	1,568,992.54	56,336,000	1,579,469.39	76,797,000	2,182,498.60
Grand Total	93,210,000	4,033,017.61	84,956,000	4,384,875.44	79,167,000	4,429,637.65	54,993,000	4,078,829.66	56,336,000	3,874,427.94	76,797,000	4,133,370.24
	Jan-15		Feb-15		Mar-15		Apr-15		May-15		Jun-15	
NL POWER PURCHASES - DEMAND	-	2,114,303.15	-	1,581,524.57	-	2,095,763.23	-	2,708,261.12	-	1,862,032.22	-	1,921,782.27
NL POWER PURCHASES - ENERGY	80,547,000	2,292,365.28	59,854,000	1,541,126.22	89,118,000	2,414,486.47	75,615,000	1,965,910.93	51,389,000	1,542,736.54	57,184,000	1,689,756.30
Grand Total	80,547,000	4,406,668.43	59,854,000	3,122,650.79	89,118,000	4,510,249.70	75,615,000	4,674,172.05	51,389,000	3,404,768.76	57,184,000	3,611,538.57
	Jan-16		Feb-16		Mar-16		Apr-16		May-16		Jun-16	
NL POWER PURCHASES - DEMAND	-	1,413,921.09	-	1,774,970.72	-	1,875,967.27	-	2,715,827.65	-	2,515,208.95	-	1,340,756.14
NL POWER PURCHASES - ENERGY	78,329,000	2,246,510.48	71,325,000	2,037,566.48	56,635,000	1,540,885.38	47,317,000	1,325,873.75	70,333,000	1,957,829.55	91,718,000	2,358,566.85
Grand Total	78,329,000	3,660,431.57	71,325,000	3,812,537.20	56,635,000	3,416,852.65	47,317,000	4,041,701.40	70,333,000	4,473,038.50	91,718,000	3,699,322.99
	Jan-17		Feb-17		Mar-17		Apr-17		May-17		Jun-17	
NL POWER PURCHASES - DEMAND	-	1,702,036.24	-	2,046,128.67	-	2,919,886.48	-	1,377,975.23	-	3,558,991.64	-	1,914,658.31
NL POWER PURCHASES - ENERGY	89,706,000	2,506,395.01	71,213,000	1,636,230.02	73,803,000	1,829,415.10	63,191,000	1,526,186.05	31,352,000	862,696.41	62,565,000	1,536,097.64
Grand Total	89,706,000	4,208,431.25	71,213,000	3,682,358.69	73,803,000	4,749,301.58	63,191,000	2,904,161.28	31,352,000	4,421,688.05	62,565,000	3,450,755.95
	Jan-18		Feb-18		Mar-18		Apr-18		May-18		Jun-18	
NL POWER PURCHASES - DEMAND	-	1,746,619.31	-	2,102,184.09	-	2,207,673.26	-	3,066,376.50	-	2,970,661.02	-	2,365,695.93
NL POWER PURCHASES - ENERGY	83,614,000	2,027,833.90	56,029,000	1,350,034.31	88,629,000	2,004,423.90	72,208,000	1,581,436.44	51,479,000	1,195,697.82	70,590,000	1,679,048.67
Grand Total	83,614,000	3,774,453.21	56,029,000	3,452,218.40	88,629,000	4,212,097.16	72,208,000	4,647,812.94	51,479,000	4,166,358.84	70,590,000	4,044,744.60
	Jan-19		Feb-19		Mar-19		Apr-19		May-19		Jun-19	
NL POWER PURCHASES - DEMAND	-	2,859,636.35	-	2,243,003.82	-	2,334,573.08	-	3,495,603.93	-	2,532,487.34	-	2,235,726.91
NL POWER PURCHASES - ENERGY	77,340,000	2,108,854.70	60,144,000	1,279,091.08	85,702,000	2,090,675.11	48,255,000	1,217,879.31	50,883,000	1,478,308.36	70,927,000	1,806,765.83
Grand Total	77,340,000	4,968,491.05	60,144,000	3,522,094.90	85,702,000	4,425,248.19	48,255,000	4,713,483.24	50,883,000	4,010,795.70	70,927,000	4,042,492.74
	Jan-20		Feb-20		Mar-20		Apr-20		May-20		Jun-20	
NL POWER PURCHASES - DEMAND	-	2,640,833.18	-	1,768,766.90	-	2,524,714.96	-	2,874,038.68	-	2,486,445.40	-	2,206,361.49
NL POWER PURCHASES - ENERGY	75,213,000	1,800,001.72	63,409,000	1,583,673.49	62,982,000	1,615,731.63	31,249,000	982,513.98	31,996,000	891,937.09	69,076,000	1,752,256.14
Grand Total	75,213,000	4,440,834.90	63,409,000	3,352,440.39	62,982,000	4,140,446.59	31,249,000	3,856,552.66	31,996,000	3,378,382.49	69,076,000	3,958,617.63
	Jan-21		Feb-21		Mar-21		Apr-21		May-21		Jun-21	
NL POWER PURCHASES - DEMAND	-	3,136,262.20	-	2,031,069.68	-	2,658,589.83	-	3,145,267.34	-	2,884,079.43	-	2,699,212.40
NL POWER PURCHASES - ENERGY	68,970,000	1,784,746.52	71,642,000	1,684,336.99	64,285,000	1,650,750.93	59,281,000	1,465,245.95	36,672,000	965,896.40	57,901,000	1,492,707.89
Grand Total	68,970,000	4,921,008.72	71,642,000	3,715,406.67	64,285,000	4,309,340.76	59,281,000	4,610,513.29	36,672,000	3,849,975.83	57,901,000	4,191,920.29
NL POWER PURCHASES - DEMAND	-	26,369,538.95	-	22,096,647.55	-	29,286,512.00	-	32,326,652.34	-	31,182,392.96	-	24,931,461.31
NL POWER PURCHASES - ENERGY	1,038,901,000	28,384,945.16	885,552,000	22,151,439.65	957,256,000	24,456,787.95	781,096,000	20,605,139.39	716,259,000	19,742,220.90	925,580,000	25,035,400.28
Ten Year Grand Total	1,038,901,000	54,754,484.11	885,552,000	44,248,087.20	957,256,000	53,743,299.95	781,096,000	52,931,791.73	716,259,000	50,924,613.86	925,580,000	49,966,861.59

Louisville Gas and Electric Company/Kentucky Utilities Company
Case No. 2021-00393
OVEC Costs
For the Calendar Years 2010 through 2021

Jul-10		Aug-10		Sep-10		Oct-10		Nov-10		Dec-10		Total	
Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount	Quantity	Amount
-	2,383,835.62	-	1,796,281.70	-	1,607,054.45	-	2,083,424.59	-	2,212,448.90	-	2,115,390.65	-	25,681,432.41
87,051,000	2,111,053.41	110,936,000	2,877,817.20	102,876,000	2,672,705.67	93,150,000	2,397,151.89	104,889,000	2,716,023.55	121,673,000	3,089,270.85	1,213,740,000	29,939,623.14
87,051,000	4,494,889.03	110,936,000	4,674,098.90	102,876,000	4,279,760.12	93,150,000	4,480,576.48	104,889,000	4,928,472.45	121,673,000	5,204,661.50	1,213,740,000	55,621,055.55
Jul-11		Aug-11		Sep-11		Oct-11		Nov-11		Dec-11			
-	1,933,098.52	-	1,969,301.28	-	1,998,325.94	-	2,859,161.08	-	2,612,783.66	-	2,835,549.40	-	26,440,967.21
103,599,000	3,078,567.55	97,351,000	2,934,528.25	77,170,000	2,407,761.54	61,685,000	2,024,001.65	70,607,000	1,872,810.00	83,988,000	2,371,244.48	1,132,068,000	31,809,506.35
103,599,000	5,011,666.07	97,351,000	4,903,829.53	77,170,000	4,406,087.48	61,685,000	4,883,162.73	70,607,000	4,485,593.66	83,988,000	5,206,793.88	1,132,068,000	58,250,473.56
Jul-12		Aug-12		Sep-12		Oct-12		Nov-12		Dec-12			
-	2,283,538.63	-	2,292,206.84	-	1,953,558.50	-	2,190,028.45	-	2,219,805.38	-	2,496,495.98	-	27,712,196.76
84,832,000	2,504,840.86	86,592,000	2,600,644.43	66,985,000	2,231,610.29	69,553,000	2,026,412.82	89,804,000	2,572,871.74	89,892,000	2,706,789.96	989,366,000	28,996,777.33
84,832,000	4,788,379.49	86,592,000	4,892,851.27	66,985,000	4,185,168.79	69,553,000	4,216,441.27	89,804,000	4,792,677.12	89,892,000	5,203,285.94	989,366,000	56,708,974.09
Jul-13		Aug-13		Sep-13		Oct-13		Nov-13		Dec-13			
-	1,802,679.82	-	2,318,310.15	-	2,240,644.12	-	2,659,292.39	-	2,625,880.50	-	2,935,840.76	-	29,494,048.06
82,318,000	2,423,871.34	72,894,000	2,135,246.60	60,925,000	1,915,933.70	81,417,000	2,545,841.35	74,545,000	2,274,394.46	84,980,000	2,547,733.59	854,053,000	26,068,132.53
82,318,000	4,226,551.16	72,894,000	4,453,556.75	60,925,000	4,156,577.82	81,417,000	5,205,133.74	74,545,000	4,900,274.96	84,980,000	5,483,574.35	854,053,000	55,562,180.59
Jul-14		Aug-14		Sep-14		Oct-14		Nov-14		Dec-14			
-	1,740,292.95	-	1,868,279.19	-	1,998,141.94	-	2,405,751.46	-	2,051,378.05	-	2,752,925.41	-	25,450,389.00
84,804,000	2,288,473.37	74,767,000	2,257,779.76	76,281,000	2,254,153.24	54,586,000	1,487,412.83	69,101,000	1,981,062.27	91,239,000	2,463,692.62	896,237,000	25,033,112.63
84,804,000	4,028,766.32	74,767,000	4,126,058.95	76,281,000	4,252,295.18	54,586,000	3,893,164.29	69,101,000	4,032,440.32	91,239,000	5,216,618.03	896,237,000	50,483,501.63
Jul-15		Aug-15		Sep-15		Oct-15		Nov-15		Dec-15			
-	2,107,982.86	-	2,057,533.24	-	2,031,019.20	-	2,564,800.28	-	1,960,441.00	-	3,054,141.11	-	26,059,584.25
58,892,000	1,747,777.90	74,362,000	2,119,255.18	78,763,000	2,163,437.21	58,237,000	1,662,088.22	40,614,000	1,410,748.99	37,363,000	1,237,076.31	761,938,000	21,786,765.55
58,892,000	3,855,760.76	74,362,000	4,176,788.42	78,763,000	4,194,456.41	58,237,000	4,226,888.50	40,614,000	3,371,189.99	37,363,000	4,291,217.42	761,938,000	47,846,349.80
Jul-16		Aug-16		Sep-16		Oct-16		Nov-16		Dec-16			
-	1,961,580.44	-	2,004,634.93	-	1,747,961.46	-	2,436,586.81	-	2,268,723.85	-	2,894,643.57	-	24,950,782.88
94,046,000	2,481,836.91	80,828,000	2,106,581.15	81,631,000	2,184,653.88	46,173,000	1,194,303.50	61,791,000	1,616,692.37	84,236,000	2,182,525.91	864,362,000	23,233,826.21
94,046,000	4,443,417.35	80,828,000	4,111,216.08	81,631,000	3,932,615.34	46,173,000	3,630,890.31	61,791,000	3,885,416.22	84,236,000	5,077,169.48	864,362,000	48,184,609.09
Jul-17		Aug-17		Sep-17		Oct-17		Nov-17		Dec-17			
-	2,246,252.47	-	2,122,740.11	-	2,741,649.53	-	2,702,402.54	-	2,524,683.85	-	2,547,701.39	-	28,405,106.46
71,643,000	1,685,946.02	63,203,000	1,520,220.04	39,021,000	998,625.68	61,160,000	1,515,838.55	84,981,000	2,100,821.01	81,891,000	1,919,505.63	793,729,000	19,637,977.16
71,643,000	3,932,198.49	63,203,000	3,642,960.15	39,021,000	3,740,275.21	61,160,000	4,218,241.09	84,981,000	4,625,504.86	81,891,000	4,467,207.02	793,729,000	48,043,083.62
Jul-18		Aug-18		Sep-18		Oct-18		Nov-18		Dec-18			
-	2,232,905.63	-	2,302,789.57	-	2,421,049.84	-	2,804,038.41	-	2,074,151.49	-	2,638,137.82	-	28,932,282.87
79,985,000	1,857,671.01	77,243,000	1,771,607.21	56,874,000	1,470,429.94	56,975,000	1,246,617.18	82,808,000	1,863,410.35	82,803,000	1,871,060.83	859,237,000	19,919,271.56
79,985,000	4,090,576.64	77,243,000	4,074,396.78	56,874,000	3,891,479.78	56,975,000	4,050,655.59	82,808,000	3,937,561.84	82,803,000	4,509,198.65	859,237,000	48,851,554.43
Jul-19		Aug-19		Sep-19		Oct-19		Nov-19		Dec-19			
-	2,331,432.90	-	2,321,600.59	-	2,448,975.73	-	2,621,588.00	-	2,161,407.91	-	2,585,597.85	-	30,171,634.41
82,455,000	1,899,815.67	75,558,000	1,900,477.19	64,621,000	1,554,522.45	88,761,000	2,157,445.85	82,942,000	1,929,757.46	90,650,000	2,344,538.29	878,238,000	21,768,131.30
82,455,000	4,231,248.57	75,558,000	4,222,077.78	64,621,000	4,003,498.18	88,761,000	4,779,033.85	82,942,000	4,091,165.37	90,650,000	4,930,136.14	878,238,000	51,939,765.71
Jul-20		Aug-20		Sep-20		Oct-20		Nov-20		Dec-20			
-	2,357,288.98	-	2,637,062.54	-	2,318,459.06	-	2,646,051.99	-	2,386,611.15	-	3,048,892.02	-	29,895,526.35
77,240,000	1,893,566.19	65,403,000	1,680,858.60	50,688,000	1,194,050.57	42,446,000	1,287,425.98	75,548,000	1,896,632.11	73,357,000	1,733,380.58	718,607,000	18,312,028.08
77,240,000	4,250,855.17	65,403,000	4,317,921.14	50,688,000	3,512,509.63	42,446,000	3,933,477.97	75,548,000	4,283,243.26	73,357,000	4,782,272.60	718,607,000	48,207,554.43
Jul-21		Aug-21		Sep-21		Oct-21		Nov-21		Dec-21			
-	2,650,601.46	-	2,687,359.30	-	2,532,656.37	-	2,770,838.34	-	2,716,012.74	-	2,970,352.31	-	32,882,301.40
74,767,000	1,918,208.39	79,134,000	2,031,432.14	77,109,000	1,987,771.95	45,458,000	1,215,715.29	41,020,000	1,196,681.49	57,994,000	1,531,667.91	734,233,000	18,925,161.85
74,767,000	4,568,809.85	79,134,000	4,718,791.44	77,109,000	4,520,428.32	45,458,000	3,986,553.63	41,020,000	3,912,694.23	57,994,000	4,502,020.22	734,233,000	51,807,463.25
-	26,031,490.28	-	26,378,099.44	-	26,039,496.14	-	30,743,964.34	-	27,814,328.48	-	32,875,668.27	-	336,076,252.06
981,632,000	25,891,628.62	958,271,000	25,936,447.75	832,944,000	23,035,656.12	759,601,000	20,760,255.11	878,650,000	23,431,905.80	980,066,000	25,998,486.96	10,695,808,000	285,430,313.69
981,632,000	51,923,118.90	958,271,000	52,314,547.19	832,944,000	49,075,152.26	759,601,000	51,504,219.45	878,650,000	51,246,234.28	980,066,000	58,874,155.23	10,695,808,000	621,506,565.75

LG&E
a PPL company

Louisville Gas and Electric Company
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.lge-ku.com

Robert M. Conroy
Director - Rates
T 502-627-3324
F 502-627-3213
robert.conroy@lge-ku.com

Jeff DeRouen, Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, Kentucky 40602-0615

RECEIVED
MAR 16 2011
PUBLIC SERVICE
COMMISSION

March 16, 2011

Dear Mr. DeRouen:

Enclosed for filing please find an original and ten copies of the Verified Application of Louisville Gas and Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract.

An extra copy of the Application is also enclosed to be file stamped and returned.

Sincerely,

Robert M. Conroy

cc: Hon. Dennis Howard II, Office of the Attorney General
Hon. Michael L. Kurtz, Kentucky Industrial Utilities Customers
Hon. Kendrick R. Riggs, Stoll Keenon Ogden

Enclosure

RECEIVED
MAR 16 2011
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

VERIFIED APPLICATION OF LOUISVILLE GAS & ELECTRIC COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG-TERM PURCHASE CONTRACT	)))))	**CASE NO. 2011-______**

VERIFIED APPLICATION

Pursuant to KRS 278.300, Louisville Gas and Electric Company ("LG&E" or the "Company") hereby requests that the Kentucky Public Service Commission ("Commission") issue an order approving LG&E's entrance into an Amended and Restated Inter-Company Power Agreement dated as of September 10, 2010, which will allow the Company to continue to obtain low-cost energy and capacity from the Ohio Valley Electric Corporation ("OVEC"), as more fully described herein. In support of this Application, the Company states as follows:

1. The Company's full name is Louisville Gas and Electric Company. The Company's post office address is 220 West Main Street, Louisville, Kentucky 40202. LG&E is a Kentucky corporation, a utility as defined by KRS 278.010(3)(a) and (b) and provides retail electric service to approximately 393,000 customers and retail gas service to approximately 318,000 customers in seventeen counties in Kentucky. In accordance with 807 KAR 5:001 § 11(a), a description of LG&E's properties is set out in Exhibit 1 to this Application. A certified copy of the Company's Articles of Incorporation was filed with the Commission in Case No. 2010-00204, *In the Matter of: The Joint Application of PPL Corporation, E.ON AG, E.ON U.S. Investments Corp., E.ON U.S. LLC, Louisville Gas & Electric Company and*

Kentucky Utilities Company for Approval of an Acquisition of Ownership and Control of Utilities and is incorporated by reference herein pursuant to 807 KAR 5:001, Section 8(3).

2. This Application relates to the extension of the current Inter-Company Power Agreement (the "Current ICPA"), a wholesale power contract between OVEC and its various owners or their affiliates, including the Company. Exhibit 2 to this Application is a copy of the Amended and Restated Inter-Company Power Agreement, dated as of September 10, 2010 (the "Amended ICPA"), which extends the Current ICPA, and which the Company signed on October 25, 2010.[1] The Amended ICPA is subject to the Federal Energy Regulatory Commission's ("FERC") jurisdiction under the Federal Power Act, and will be filed with FERC by March 31, 2011. The Company will provide a copy of the FERC filing to the Commission within two business days of making the FERC filing.

3. OVEC was formed in the early 1950s by the Company and several other holding companies and utilities located in the Ohio Valley region in response to the United States Atomic Energy Commission's ("AEC") request to supply the electric power and energy needs of the AEC's planned uranium enrichment plant in Pike County, Ohio. Accordingly, OVEC and its wholly owned subsidiary Indiana-Kentucky Electric Company ("IKEC")[2] built two coal-fired generating stations with a total capacity of approximately 2,365 MW and entered into a long-term power agreement (the "DOE Power Agreement") with the United States. The DOE Power Agreement gave AEC, and subsequently the Department of Energy ("DOE"), the right to essentially all of the capacity of OVEC's generating facilities.

---

[1] LG&E's sister utility, Kentucky Utilities Company, is also a party to the Amended ICPA, and is concurrently filing a similar Application with the Commission.
[2] For convenience, OVEC and IKEC are referred to collectively as OVEC, although IKEC is not a party to the Amended ICPA.

4. To support the DOE Power Agreement, OVEC and its owners or their affiliates, including the Company (collectively the "Sponsors" and individually a "Sponsor") entered into an Inter-Company Power Agreement ("ICPA"), a fifty-year power supply agreement, dated as of July 10, 1953 ("Original ICPA").[3] The Original ICPA granted each Sponsor the right to purchase "surplus power" and energy not required by DOE in proportion to the Sponsor's specified Power Participation Ratio ("PPR"). DOE, after agreeing to several releases to the Sponsors of its contractual right to power and energy, ultimately terminated the DOE Power Agreement as of April 30, 2003. As a result, all of OVEC's generation capacity became "surplus" and each of the Sponsors, including the Company, has access to its PPR share of OVEC's relatively low cost generation.

5. In 2004, the Sponsors entered into the Current ICPA, which extended its term from March 13, 2006 to March 13, 2026. The 2004 extension allowed the Sponsors to continue receiving power and allocating costs under the ICPA. Additionally, the extension allowed the $365 million selective catalytic reduction ("SCR") debt to be refinanced as unsecured debt and allowed financing of the $80 million Kyger Powder River Basin coal switch project in a combined financing that was finalized on December 20, 2005. The Commission approved this extension on December 30, 2004, in Case No. 2004-00396, *In the Matter of: Application of Louisville Gas & Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract.*

6. OVEC now recommends extending the ICPA to take advantage of reduced financing costs and to amortize its debt over a longer time period. The debt restructuring would reduce the total debt service portion of the Current ICPA demand charge by approximately 28%

[3] The fifty-year term ran from the date that all of OVEC's generating units were placed in commercial operation, not from the date of the Original ICPA.

per year. This savings would be passed along to the Sponsors by reducing the energy costs by approximately $1/MWh from the extension's effective date through the currently applicable term expiration in 2026. It is projected that LG&E and its sister utility, Kentucky Utilities Company, would save approximately $900,000 per year (on a combined basis) between the extension's effective date and 2026 for a total combined savings of approximately $14.3 million. To ensure these savings to the Sponsors, OVEC and its Sponsors have entered into the Amended ICPA, which extends the term of the Current ICPA for an additional fourteen years to June 30, 2040. The effectiveness of the Amended ICPA is expressly contingent upon the receipt of all necessary regulatory consents or approvals.

7. The Amended ICPA continues, without change, the demand charges established in the Current ICPA (set forth in Section 5.03 of the Amended ICPA). The monthly demand charge permits OVEC to recover its total cost of owning, financing, operating, and maintaining its generation and transmission facilities. Each Sponsor is required to pay its portion, based on its PPR share, of demand charges, regardless of the amount of energy such Sponsor purchases from OVEC during any given month. In addition, demand charges may be payable in the event of an early termination of the Amended ICPA. This arrangement is typical of negotiated power sales agreements, which often contain a demand charge or other component intended to permit recovery of the seller's fixed and variable costs.

8. The Amended ICPA also continues, without change, the "minimum loading" provisions (set forth in Section 5.05 of the Amended ICPA), requiring each Sponsor to either schedule delivery of its portion of OVEC's "total minimum generating output" or pay for any increased costs caused by failure to schedule and take its minimum output. These provisions are intended to improve the economic dispatch of OVEC's generation and to assign the costs

resulting from the failure of a Sponsor to schedule its minimum portion of such generation (such as additional maintenance costs associated with frequent ramping up and down of generating units, and operation of units below minimum output levels for coal-fired generation). These costs are assigned directly to the responsible Sponsor, rather than spread among all Sponsors. "Minimal loading" provisions are similar to provisions found in comparable arrangements involving joint ownership of generating facilities, and serve to improve dispatch and properly assign operating costs.

9. The Amended ICPA will permit the Company to continue its existing, beneficial relationship with OVEC, which has been in place for nearly sixty years. The Company will continue to receive its share of OVEC's generation in exchange for payment of OVEC's relatively low costs. Because of the relatively low cost of the OVEC generation, the Company utilizes the majority of the energy available from OVEC, particularly during peak periods.

10. The Company has not and will not act as a guarantor for OVEC's debt or other securities; however, the Amended ICPA requires the Sponsors to pay for replacement costs, additional facility costs, post-retirement benefits costs, and the costs associated with decommissioning the OVEC units (*see* Amended ICPA Article 7), which requirements the Commission approved in Case No. 2004-00396 (*see* Paragraph 5 above).[4] Furthermore, the Company will not issue any securities or other evidence of indebtedness for the purpose of financing its participation in the Amended ICPA. It is anticipated, however, that OVEC may use the Amended ICPA to support its financing.

11. Other than the Amended ICPA, which is expressly contingent upon receiving all necessary regulatory approvals, no contracts have been made with respect to the matters herein.

---

[4] The original ICPA, executed in 1953, contained a requirement obligating the Sponsors to pay for replacement parts; the cost of additional facilities was not discussed in the original ICPA.

12. The Company is seeking the Commission's approval of the Amended ICPA under KRS 278.300 because of the precedent set in Administrative Case No. 350, *In the Matter of the Consideration and Determination of the Appropriateness of Implementing a Rate Making Standard Pertaining to the Purchase of Long-Term Wholesale Power by Electric Utilities as Required in Section 712 of the Energy Policy Act of 1992*. In its October 5, 1993 Final Order in that proceeding, the Commission encouraged, but declined to require, utilities to file long-term power purchase contracts for pre-approval:

> [T]hese Contracts [Power Purchase Contracts] may well require prior approval under KRS 278.300 if they constitute evidence of indebtedness. In particular, the inclusion in such Contracts of minimum payment obligations or take/pay provisions may necessitate prior approval.

As discussed in Paragraphs 7 and 8 above, the Amended ICPA continues to contain firm demand charge and minimum loading provisions. Moreover, the Commission asserted jurisdiction over and approved the Current ICPA for the Company in Case No. 2004-00396, as discussed in Paragraph 5 above.

13. Exhibit 3 to this Application contains a financial exhibit as required by 807 KAR 5:001, Section 11(2)(a) as described by 807 KAR 5:001, Section 6. The twelve-month period in Exhibit 3 ends on January 31, 2011. Exhibit 3 also contains information required by 807 KAR 5:001, Section 11(2)(b), although the Company notes that an Indenture of Mortgage or Deed of Trust will not be involved in the transaction described herein.

14. Other requirements of the Commission's regulations are inapplicable. The Company proposes to enter into a power supply contract, not to issue notes, bonds, or similar evidence of indebtedness. Thus, there are no stock, notes or bonds, or uses of the proceeds from same to discuss (807 KAR 5:001, Section 11(1)(b) and (c)), and no property is being acquired,

constructed, improved or extended (807 KAR 5:001, Section 11(1)(d) and 11(2)(c)). Likewise, no obligations are being discharged or refunded (807 KAR 5:001, Section (1)(e)).

15. Because numerous regulatory and other actions must be undertaken and coordinated by OVEC and the Sponsors, the Company asks the Commission to consider this Application as expeditiously as possible.

WHEREFORE, Louisville Gas and Electric Company respectfully asks the Commission to enter an order pursuant to KRS 278.300 approving its entrance into the Amended and Restated Inter-Company Power Agreement dated September 10, 2010.

Dated: March 16, 2011

Respectfully submitted,

Kendrick R. Riggs
W. Duncan Crosby III
Stoll Keenon Ogden PLLC
2000 PNC Plaza
500 West Jefferson Street
Louisville, Kentucky 40202
Telephone: (502) 333-6000

Allyson K. Sturgeon
Senior Corporate Attorney
LG&E and KU Energy LLC
220 West Main Street
Louisville, KY 40202
Telephone: (502) 627-2088

Counsel for Louisville Gas and Electric Company

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JEFFERSON)

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is Vice President, State Regulation and Rates for 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 foregoing verified application, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of March 2011.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2014

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing Verified Application was served on the following persons on the 16th day of March, 2011, U.S. mail, postage prepaid:

Dennis G. Howard II
Lawrence W. Cook
Assistant Attorneys General
Office of the Attorney General
Office of Rate Intervention
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

Michael L. Kurtz
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202

Counsel for Louisville Gas and Electric Company

Exhibit 1

LOUISVILLE GAS AND ELECTRIC COMPANY
(807 KAR 5:001, Section 11, Item 1 (a))

A DESCRIPTION OF APPLICANT'S PROPERTY, INCLUDING A STATEMENT OF THE NET ORIGINAL COST OF THE PROPERTY AND THE COST THEREOF TO APPLICANT

January 31, 2011

The applicant's generating, transmission and distribution systems described herein are calculated annually. As of December 31, 2010, the applicant owned and operated 10 coal fired steam electric generating units having a total capacity of 2,552 Mw; 14 combustion turbine generating units having a total capacity of 667 Mw; and 1 hydroelectric generating station, the operation of which is affected by the water level and flow of the Ohio River, having a total capacity of 52 Mw.

On January 22, 2011, construction on TC2 was completed, and the unit was placed in service under interim operations, at full load, but using restricted fuels. The construction contractor and the owners are analyzing arrangements for completing modifications to the unit during scheduled outages in 2011. The applicant owns a 14.25% interest of TC2 of which the applicant's share is 108 Mw.

The applicant's owned electric transmission system included 45 substations (32 of which are shared with the distribution system) with a total capacity of approximately 6,760 MVA and 911 miles of lines. The electric distribution system included 95 substations (32 of which are shared with the transmission system) with a total capacity of approximately 5,224 MVA, 3,920 miles of overhead lines and 2,350 miles of underground conduit.

The applicant operated underground gas storage facilities with a current working gas capacity of 15 million Mcf used for seasonal and peak-day augmentation of winter pipeline supply.

The applicant's natural gas transmission system included 380 miles of transmission mains, consisting of 255 miles of natural gas transmission lines, 119 miles of natural gas storage lines and 6 miles of natural gas combustion turbine lines. The applicant's natural gas distribution system includes 4,235 miles of distribution mains.

Other properties include an office building, service centers, warehouses, garages and other structures and equipment, the use of which is common to both the electric and gas departments.

The net original cost of the property and cost thereof to the applicant at January 31, 2011, was:

	Electric	Gas	Common	Total	
Original Cost	$ 3,786,511,184	$ 724,614,425	$ 239,652,366	$ 4,750,777,975	
Less Reserve for Depreciation	1,511,550,313	172,369,796	95,223,698	1,779,143,807	*
Net Original Cost	2,274,960,871	552,244,629	144,428,668	2,971,634,168	
Allocation of Common To Electric and Gas	105,432,928	38,995,740	(144,428,668)	-	
Total	$ 2,380,393,799	$ 591,240,369	$ -	$ 2,971,634,168	

* Excludes $273,032,787 related to cost of removal reserves that is not included in the reserve in the Financial Statements and Additional Information, but instead is included as a regulatory liability.

Exhibit 2

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge*. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of \$2.089 multiplied by the total number of shares of capital stock of the par value of \$100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); <u>provided that</u>, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge*. The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs*. To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments*. The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver.* Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation; the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties.* Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in <u>Schedule 10.01(c)</u> hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default.* If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________

Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________

Its ______________________

APPALACHIAN POWER COMPANY

By ______________________

Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________

Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________

Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________

Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________

Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________

Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________

Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________

Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its VICE PRESIDENT

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________
Its ______________________

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By [signature]
Its Vice President

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

030860-0015-02023-Active.12026116.4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________
Its ______________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By Thomas J. Kolup
Its VICE PRESIDENT

APPALACHIAN POWER COMPANY

By ______________________
Its ______________________

BUCKEYE POWER GENERATING, LLC

By ______________________
Its ______________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________
Its ______________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________
Its ______________________

DUKE ENERGY OHIO, INC.

By ______________________
Its ______________________

FIRSTENERGY GENERATION CORP.

By ______________________
Its ______________________

INDIANA MICHIGAN POWER COMPANY

By ______________________
Its ______________________

KENTUCKY UTILITIES COMPANY

By ______________________
Its ______________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By Anthony J. Ahern
Its President & CEO

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

030860-0015-02023-Active.12026116 4

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By Gary Stephenson
Its EXECUTIVE VICE PRESIDENT
Gary Stephenson

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By ____________________
Its ____________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION	ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
By ____________________ Its ____________________	By ____________________ Its ____________________
APPALACHIAN POWER COMPANY	BUCKEYE POWER GENERATING, LLC
By ____________________ Its ____________________	By ____________________ Its ____________________
COLUMBUS SOUTHERN POWER COMPANY	THE DAYTON POWER AND LIGHT COMPANY
By ____________________ Its ____________________	By ____________________ Its ____________________
DUKE ENERGY OHIO, INC.	FIRSTENERGY GENERATION CORP.
By ____________________ Its ____________________	By Gary R Leidich Its President
INDIANA MICHIGAN POWER COMPANY	KENTUCKY UTILITIES COMPANY
By ____________________ Its ____________________	By ____________________ Its ____________________

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers as of September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ____________________
Its ____________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ____________________
Its ____________________

APPALACHIAN POWER COMPANY

By ____________________
Its ____________________

BUCKEYE POWER GENERATING, LLC

By ____________________
Its ____________________

COLUMBUS SOUTHERN POWER COMPANY

By ____________________
Its ____________________

THE DAYTON POWER AND LIGHT COMPANY

By ____________________
Its ____________________

DUKE ENERGY OHIO, INC.

By ____________________
Its ____________________

FIRSTENERGY GENERATION CORP.

By ____________________
Its ____________________

INDIANA MICHIGAN POWER COMPANY

By ____________________
Its ____________________

KENTUCKY UTILITIES COMPANY

By [signature]
Its Sr Vice President

030860-0015-02023-Active 12026116.4

LOUISVILLE GAS AND ELECTRIC COMPANY

By [signature]
Its VP Trans. & Generation Services

MONONGAHELA POWER COMPANY

By ______________________
Its ______________________

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ________________________
Its ________________________

MONONGAHELA POWER COMPANY

By ________________________
Its ________________________

OHIO POWER COMPANY

By ________________________
Its ________________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ________________________
Its ________________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

MONONGAHELA POWER COMPANY

By ____________________
Its General Manager, Electric Supply

OHIO POWER COMPANY

By ____________________
Its ____________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ____________________
Its ____________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________
Its ______________________

MONONGAHELA POWER COMPANY

By ______________________
Its ______________________

OHIO POWER COMPANY

By ______________________
Its ______________________

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By Ronald E. Christian
Its President

PENINSULA GENERATION COOPERATIVE

By Daniel H. DeCoeur

Its President

APPROVED AS TO FORM:

BRIAN E. VALICE
ATTORNEY FOR PENINSULA
GENERATION COOPERATIVE

SCHEDULE 10.01(c)

Allegheny Energy Supply Company, L.L.C.

and

Monongahela Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Appalachian Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Approval of the Virginia State Corporation Commission

Filing with the Public Service Commission of West Virginia

SCHEDULE 10.01(c)

Buckeye Power Generating, LLC

None

SCHEDULE 10.01(c)

Columbus Southern Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

The Dayton Power and Light Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Duke Energy Ohio, Inc.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

FirstEnergy Generation Corp.

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Indiana Michigan Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Filing with the Indiana Utility Regulatory Commission

SCHEDULE 10.01(c)

Kentucky Utilities Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Louisville Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

Consent or approval of, or filings or registrations with, the Kentucky Public Service Commission may be required

SCHEDULE 10.01(c)

Ohio Power Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

SCHEDULE 10.01(c)

Peninsula Generation Cooperative

None

SCHEDULE 10.01(c)

Southern Indiana Gas and Electric Company

Filing with, or consent or approval of, the Federal Energy Regulatory Commission

AMENDED AND RESTATED

POWER AGREEMENT

BETWEEN

OHIO VALLEY ELECTRIC CORPORATION

AND

INDIANA-KENTUCKY ELECTRIC CORPORATION

Dated as of September 10, 2010

THIS AGREEMENT, dated as of September 10, 2010 by and between OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC) and INDIANA-KENTUCKY ELECTRIC CORPORATION (herein called IKEC), hereby amends and restates in its entirety, the Power Agreement (herein called the Current Agreement), dated March 13, 2006, between OVEC and IKEC.

WITNESSETH THAT:

WHEREAS, IKEC, a wholly owned subsidiary of OVEC, designed, purchased, and constructed, and continues to own, operate and maintain a steam-electric generating station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana; and

WHEREAS, OVEC designed, purchased, and constructed, and continues to own, operate and maintain a steam-electric generating stations (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and/or the Project Transmission Facilities, and the systems of certain of the Sponsoring Companies; and

WHEREAS, IKEC owns and operates the portion of the Project Transmission Facilities located in the State of Indiana; and

WHEREAS, IKEC entered into the Current Agreement with OVEC which embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, the owners of OVEC or their affiliates that are parties to an Inter-Company Power Agreement, have amended and restated such Inter-Company Power Agreement as of the date hereof, which defines the terms and conditions governing the rights of the "Sponsoring Companies" (as defined thereunder) to receive "Available Power" (as defined thereunder) from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor; and

WHEREAS, concurrent with the amendment and restatement of the Inter-Company Power Agreement, IKEC and OVEC hereto desire to amend and restate in their entirety, the Current Agreement in order for IKEC to continue to sell to OVEC any and all power available at the Indiana Station, and energy associated therewith, and to transmit power and energy as provided herein.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

POWER AND ENERGY TRANSACTIONS

1.01 IKEC shall transmit any and all power generated at the Indiana Station by any of the generating units thereof in commercial operation and deliver such power, together with the energy associated therewith, but less the transmission losses in the facilities of IKEC applicable thereto from the 330 kV busses of the Indiana Station, at the points of delivery hereinafter designated in *Section* 1.03 hereof, and sell such power and energy at said points of delivery to OVEC. OVEC shall purchase from IKEC all such power so delivered by IKEC to OVEC at said points of delivery, together with the energy associated therewith, and shall from time to time pay IKEC therefor, amounts which, when added to revenues received by IKEC from other sources, will be sufficient to enable IKEC to pay all of its operating and other expenses, including all income and other taxes and any interest and regular amortization requirements applicable to any indebtedness for borrowed funds incurred by IKEC. For the purposes of this *Section* 1.01 the term "operating and other expenses" shall also include, without limitation, all amounts payable to suppliers of fuel requirements (including the handling and shipment thereof) in connection with the cancellation of commitments and the extension of delivery schedules, as well as all expenses accrued to pay for postemployment and postretirement benefits and the costs of the decommissioning, shutdown, demolition and closing of the Project Generating Stations.

1.02 IKEC shall transmit and deliver to OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power and the energy associated therewith supplied to IKEC by Sponsoring Companies at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto. IKEC shall transmit and deliver to Sponsoring Companies designated by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, all power, and the energy associated therewith, supplied to IKEC by OVEC at the points of delivery hereinafter designated in *Section* 1.03 hereof, less the transmission losses in the facilities of IKEC applicable thereto.

1.03 All power and energy sold, purchased, transmitted or delivered hereunder shall be 3-phase, 60-cycle, alternating current, at nominal unregulated voltage, designated for the points of delivery hereinbelow described. Power and energy transmitted, delivered and sold by IKEC to OVEC pursuant to the provisions of *Section* 1.01 hereof shall be delivered at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from IKEC to OVEC at said points. Power and energy supplied to IKEC by a Sponsoring Company for transmission to OVEC pursuant to the provisions of *Section* 1.02 hereof, shall be delivered by said Sponsoring Company to IKEC at the points where the transmission facilities of said Sponsoring Company and the transmission facilities of IKEC interconnect and shall be delivered by IKEC to OVEC and title thereto shall pass from said Sponsoring Company to OVEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect. Power and energy supplied to IKEC by OVEC for transmission to a Sponsoring Company pursuant to the provisions of *Section* 1.02 hereof shall be delivered by OVEC to IKEC at the points where the transmission facilities of OVEC and the transmission facilities of IKEC interconnect and title to such power and energy shall pass from OVEC to said Sponsoring Company at said points. Such power and energy shall be delivered by IKEC to said Sponsoring Company at the points where the transmission facilities of IKEC and the transmission facilities of said Sponsoring Company interconnect.

1.04 The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the Sponsoring Companies and the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected system operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

1.05 OVEC shall reimburse IKEC for the difference between (a) the total cost of replacements chargeable to property and plant made by IKEC, and the total cost of additional facilities and/or spare parts purchased or installed by Corporation, during any month or prior thereto (and not previously reimbursed) and (b) the amounts paid for by IKEC out of proceeds of fire or other applicable insurance protection, or out of amounts recovered from third parties responsible for damages requiring replacement. OVEC shall pay to IKEC such amount in lieu of the amounts to be paid as above provided, which, after provision for all taxes on income, shall equal the costs of the replacements reimbursable by OVEC to IKEC as above provided. The term cost of replacements, as used herein, shall include all components of costs, plus removal expense, less salvage. The amounts reimbursed by OVEC to IKEC for such replacements shall be accounted for on the books of IKEC in a special balance sheet account provided for such purposes.

ARTICLE 2

MISCELLANEOUS

2.01 This Agreement shall become effective on September 10, 2010, or to the extent necessary, such later date on which all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to OVEC, and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities.

2.02 No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, failure of equipment, or for any other cause beyond its control.

2.03 This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the receipt of all regulatory approvals, in form and substance satisfactory to the parties hereto, necessary to permit the parties hereto to perform all the duties and obligations to be performed by such parties hereunder.

2.04 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but this Agreement shall not be assigned by either party hereto without the written consent of the other, except (a) to a successor to all or substantially all the properties and assets of such party, or (b) to a trustee under an indenture securing any indebtedness of such party.

2.05 All notices and requests under this Agreement shall be in writing and shall be sufficient in all respects if delivered in person or sent by registered mail addressed to the party to be served at such party's general office or at such other address as such party may from time to time in writing designate.

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be duly executed as of the day and year first above written.

OHIO VALLEY ELECTRIC CORPORATION

By

Its Vice President and
Assistant to the President

INDIANA-KENTUCKY ELECTRIC CORPORATION

By

Its Vice President-Operations

Exhibit 3

LOUISVILLE GAS AND ELECTRIC COMPANY

FINANCIAL EXHIBIT
(807 KAR 5:001 SEC. 6)

January 31, 2011

(1) Amount and kinds of stock authorized.

75,000,000 shares of Common Stock, without par value.

(2) Amount and kinds of stock issued and outstanding.

Common Stock:
21,294,223 shares issued and outstanding, without par value, recorded at $424,334,535.

(3) Terms of preference of preferred stock whether cumulative or participating, or on dividends or assets or otherwise.

None

(4) Brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee, or trustee, amount of indebtedness authorized to be secured thereby, and the amount of indebtedness actually secured, together with any sinking fund provisions.

Date of Execution: As of October 1, 2010 (Supplemental Indentures were executed on October 15, 2010 and November 1, 2010.)
Mortgagor: Louisville Gas and Electric Company
Trustee: The Bank of New York Mellon
Amount of Authorized Debt: One quintillion dollars
Amount of Debt Secured: $1,109,304,000
Sinking Fund Provisions: None
Pledged Assets: Substantially all assets of Louisville Gas and Electric Company located in Kentucky

(5) Amount of bonds authorized, and amount issued, giving the name of the public utility which issued the same, describing each class separately, and giving date of issue, face value, rate of interest, date of maturity and how secured, together with an amount of interest paid thereon during the last 12-month period.

Secured by first mortgage lien on substantially all assets in Kentucky.

Louisville Gas and Electric Company

Date of Issue	Date of Maturity	Rate of Interest	Principal Amount: Authorized	Principal Amount: Outstanding at January 31, 2011	Interest Expense Year Ended January 31, 2011
Pollution Control Bonds					
05/19/00	05/01/27	5.375%	$ 25,000,000	$ 25,000,000	$ 1,343,750
08/09/00	08/01/30	Variable	83,335,000	83,335,000	411,339
09/11/01	09/01/27	Variable	10,104,000	10,104,000	201,107
03/06/02	09/01/26	Variable	22,500,000	22,500,000	48,965
03/06/02	09/01/26	Variable	27,500,000	27,500,000	158,927
03/22/02	11/01/27	Variable	35,000,000	35,000,000	360,444
03/22/02	11/01/27	Variable	35,000,000	35,000,000	360,769
10/23/02	10/01/32	Variable	41,665,000	41,665,000	303,370
11/20/03	10/01/33	1.900%	128,000,000	128,000,000 *	126,597
04/13/05	02/01/35	5.750%	40,000,000	40,000,000	2,300,000
04/26/07	06/01/33	5.625%	31,000,000	31,000,000	1,743,750
04/26/07	06/01/33	1.900%	35,200,000	35,200,000 *	34,814
04/26/07	06/01/33	4.600%	60,000,000	60,000,000	2,760,000
Interest Rate Swaps					7,717,031
			$ 574,304,000	$ 574,304,000	$ 17,870,863
First Mortgage Bonds					
11/16/10	11/15/15	1.625%	$ 250,000,000	$ 250,000,000	$ 846,354
11/16/10	11/15/40	5.125%	285,000,000	285,000,000	3,042,969
			$ 535,000,000	$ 535,000,000	$ 3,889,323

* On January 13, 2011, Louisville Gas and Electric (LG&E) remarketed the Louisville/Jefferson County Metro Government 2003 Series A and 2007 Series B bonds. In connection with the remarketing, each bond series was converted to a mode wherein the interest rate is fixed for an intermediate term but not the full term of the bond. The bonds will bear interest at the rate of 1.900% each, until April 2012 and June 2012, in the case of the 2003 Series A and 2007 Series B bonds, respectively. At the end of the

intermediate term, the Company must remarket the bonds or buy them back. As of January 13, 2011, the Company has no remaining repurchased bonds.

(6) Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid thereon during the last 12-month period.

There are no notes outstanding as of January 31, 2011. In connection with the PPL Corporation acquisition, on November 1, 2010, LG&E borrowed $485,000,000 from a PPL subsidiary, in order to repay loans from a subsidiary of E.ON AG. The Company used the net proceeds received from the sale of the first mortgage bonds to repay the debt owed to the PPL subsidiary arising from the borrowing.

Total interest paid for twelve months ending January 31, 2011:

E.ON AG	$ 19,990,350
PPL	1,110,075
	$ 21,100,425

(7) Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of any portion of such indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid thereon during the last fiscal year.

None, other than current and accrued liabilities.

(8) Rate and amount of dividends paid during the five previous fiscal years, and the amount of capital stock on which dividends were paid each year. (1)

Dividends on Common Stock, without par value (not based on rate per share)

2006	$ 95,000,000
2007	65,000,000
2008	40,000,000
2009	80,000,000
2010	55,000,000

(1) On November 1, 2010, PPL Corporation completed its acquisition of E.ON U.S LLC., the Company's parent. Upon completion of the acquisition, E.ON U.S. LLC was renamed LG&E and KU Energy LLC. The 21,294,223 shares are currently owned by LG&E and KU Energy LLC. From May 1998 to October 31, 2010, the 21,294,223 shares were all owned by E.ON U.S. LLC (formerly LG&E Energy LLC) and all dividends declared by LG&E's Board of Directors were paid to E.ON U.S. LLC. During the 1st quarter of 2010, LG&E declared and paid a common stock dividend of $30,000,000. During the 3rd quarter of 2010, LG&E declared and paid a common stock dividend of $25,000,000.

Dividends on 5% Cumulative Preferred Stock, $25 par value

For each of the quarters in the years 2005 – 2006, the Company declared and paid dividends of $.3125 per share on the 860,287 shares of 5% Cumulative Preferred Stock,

$25 par value, outstanding for a total of $268,841 each quarter. The annual amount of dividends for each fiscal year 2005 - 2006 was $1,075,365. All shares were redeemed on April 16, 2007. The amount of dividends declared and paid through April 16, 2007 was $316,636.

Dividends on $5.875 Cumulative Preferred Stock, without par value

For each of the quarters in the years 2005 – 2006, the Company declared and paid dividends of $1.46875 per share on the $5.875 series preferred stock outstanding. The preferred stock had a sinking fund requirement sufficient to retire a minimum of 12,500 shares on July 15 of each year commencing with July 15, 2003, and the remaining 187,500 shares on July 15, 2008 at $100 per share. The Company redeemed 12,500 shares in accordance with these provisions annually on July 15, 2003 through July 15, 2006. The 200,000 remaining shares were redeemed April 16, 2007.

Annual dividends and interest on preferred stock, without par value for the previous five fiscal years were:

2006	$1,211,719
2007	345,972
2008	0
2009	0
2010	0

Dividends on Auction Rate Cumulative Preferred Stock, without par value

Declared Date	Payment Date	Rate Per Share	Amount
March 2005	04/15/05	0.75000	$375,000
June 2005	07/15/05	0.97500	487,500
September 2005	10/17/05	0.97500	487,500
December 2005	01/17/06	1.10000	550,000
			$1,900,000
March 2006	04/15/06	1.20000	$600,000
June 2006	07/15/06	1.33750	668,750
September 2006	10/15/06	1.44750	723,750
December 2006	01/15/07	1.27500	637,500
			$2,630,000
March 2007	04/13/07	1.25000	$625,000
			$625,000

Dividend is based on 500,000 shares for all periods. All shares were redeemed on April 16, 2007.

(9) Detailed Income Statement, Balance Sheet and Statement of Retained Earnings

Monthly Financial and Operating Reports are filed each month with the Kentucky Public Service Commission. Attached are detailed Statements of Income, Balance Sheets and Retained Earnings for the Company for the period ending January 31, 2011.

Louisville Gas and Electric Company
Balance Sheets as of January 31, 2011

Assets		Liabilities and Proprietary Capital	
Utility Plant		Proprietary Capital	
Utility Plant at Original Cost	$ 4,750,777,974.71	Common Stock	$ 425,170,424.09
Less Reserves for Depreciation and Amortization	2,049,262,226.20	Less: Common Stock Expense	835,888.64
		Paid-In Capital	83,581,499.00
Total	2,701,515,748.51	Other Comprehensive Income	-
		Retained Earnings	846,905,423.78
Investments		Total Proprietary Capital	1,354,821,458.23
Ohio Valley Electric Corporation	594,286.00		
Nonutility Property - Less Reserve	11,879.20	Pollution Control Bonds - Net of Reacquired Bonds	574,304,000.00
Special Funds	16,266,282.58	First Mortgage Bonds	531,075,004.16
		LT Notes Payable to Associated Companies	-
Total	16,872,447.78		
		Total Long-Term Debt	1,105,379,004.16
Current and Accrued Assets		Total Capitalization	2,460,200,462.39
Cash	10,946,085.86		
Special Deposits	3,590,045.06	Current and Accrued Liabilities	
Temporary Cash Investments	1,861.08	ST Notes Payable to Associated Companies	39,801,000.00
Accounts Receivable - Less Reserve	172,877,770.06	Accounts Payable	95,342,791.32
Accounts Receivable from Associated Companies	18,031,905.66	Accounts Payable to Associated Companies	16,395,004.37
Materials and Supplies - At Average Cost		Customer Deposits	23,571,825.06
Fuel	63,040,020.16	Taxes Accrued	11,594,182.53
Plant Materials and Operating Supplies	29,472,535.23	Interest Accrued	7,648,967.20
Stores Expense	4,987,130.53	Miscellaneous Current and Accrued Liabilities	26,764,921.93
Gas Stored Underground	43,600,442.97		
Emission Allowances	2,624.91	Total	221,118,692.41
Prepayments	6,932,677.50		
Miscellaneous Current and Accrued Assets	453,145.30		
Total	353,936,244.32	Deferred Credits and Other	
		Accumulated Deferred Income Taxes	473,518,807.92
		Investment Tax Credit	45,315,209.13
Deferred Debits and Other		Regulatory Liabilities	65,743,017.64
Unamortized Debt Expense	13,553,077.84	Customer Advances for Construction	8,492,300.89
Unamortized Loss on Bonds	21,833,646.50	Asset Retirement Obligations	52,869,451.55
Accumulated Deferred Income Taxes	53,869,965.22	Other Deferred Credits	6,909,404.21
Deferred Regulatory Assets	353,138,961.12	Miscellaneous Long-Term Liabilities	33,228,101.47
Other Deferred Debits	901,719.66	Accum Provision for Postretirement Benefits	148,226,363.34
Total	443,297,370.34	Total	834,302,656.15
Total Assets	$ 3,515,621,810.95	Total Liabilities and Stockholders' Equity	$ 3,515,621,810.95

Louisville Gas and Electric Company
Comparative Statement of Income
January 31, 2011

	Year Ended 1/31/2011
Electric Operating Revenues	$ 1,032,051,999.60
Gas Operating Revenues	312,177,991.63
Total Operating Revenues	1,344,229,991.23
Fuel for Electric Generation	371,789,895.26
Power Purchased	55,167,479.44
Gas Supply Expenses	173,365,821.30
Other Operation Expenses	226,993,825.00
Maintenance	112,515,683.87
Depreciation	131,720,871.83
Amortization Expense	7,646,851.79
Regulatory Credits	(4,457,140.11)
Taxes	
Federal Income	34,128,940.20
State Income	7,005,404.44
Deferred Federal Income - Net	27,667,011.82
Deferred State Income - Net	2,370,024.44
Property and Other	22,769,139.40
Investment Tax Credit	-
Amortization of Investment Tax Credit	(2,491,983.00)
Loss (Gain) from Disposition of Allowances	(34,460.14)
Accretion Expense	3,338,204.86
Total Operating Expenses	1,169,495,570.40
Net Operating Income	174,734,420.83
Other Income Less Deductions	10,871,169.70
Income Before Interest Charges	185,605,590.53
Interest on Long-Term Debt	43,640,294.92
Amortization of Debt Expense - Net	1,822,005.63
Other Interest Expenses	2,526,924.63
Total Interest Charges	47,989,225.18
Net Income	$ 137,616,365.35

Louisville Gas and Electric Company
Analysis of Retained Earnings
January 31, 2011

	Year Ended 1/31/11
Balance at Beginning of Period................................	$ 764,289,058.43
Add:	
Net Income (Loss) for Period.............................	137,616,365.35
Deduct:	
Common Dividends	
Common Stock Without Par Value.................	55,000,000.00
Balance at End of Period.......................................	$ 846,905,423.78

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

VERIFIED APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG-TERM PURCHASE CONTRACT	))))	CASE NO. 2011-00099
VERIFIED APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG-TERM PURCHASE CONTRACT	))))	CASE NO. 2011-00100

O R D E R

On March 16, 2011, Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E and KU") filed applications seeking Commission approval of an amended wholesale power contract with the Ohio Valley Electric Corporation ("OVEC") pursuant to the provisions of KRS 278.300.

OVEC was formed in the early 1950s by LG&E and KU and several other utilities and holding companies located in the Ohio Valley region in response to the request of the United States Atomic Energy Commission ("AEC") to supply the electric power needs of the AEC's planned uranium enrichment plant in Pike County, Ohio. OVEC built two coal-fired generating stations and entered into a long-term power agreement with the United States Department of Energy ("DOE"). The agreement gave DOE the right to OVEC's generation capacity. OVEC and its owners or their affiliates, including LG&E and KU, entered into the original Inter-Company Power Agreement ("ICPA"), a 50-year power supply agreement that gave each OVEC owner the right to purchase surplus power not required by DOE in proportion to the owner's participation ratio.

Subsequent to the termination of the DOE power agreement on April 30, 2003, all of OVEC's capacity was considered to be surplus.

The current OVEC ICPA has a term that runs to March 13, 2026.[1] OVEC has recommended extending the ICPA to take advantage of reduced financing costs and to amortize its debt over a longer time period. The resulting savings would be passed on to the OVEC owners through a reduction in energy costs of approximately $1 per MWh from the extension's effective date through the currently scheduled 2026 termination date. It is estimated that LG&E and KU will save approximately $14.3 million on a combined basis over that period of time under the extended ICPA. OVEC and its owners have entered into an amended ICPA, which extends the term an additional 14 years, through June 30, 2040.

LG&E and KU state that, given the relatively low cost of the OVEC generation, they utilize the majority of the power available from OVEC, particularly during peak periods. A comparison of the cost of their own generation and the cost of their OVEC purchases show that the cost per KWh of OVEC's generation compares quite favorably to LG&E's and KU's generation costs.

At the time of the previous extension of the ICPA, OVEC commissioned an independent engineering assessment of the remaining lives and production capabilities, environmental remediation, and decommissioning of its generating facilities. At OVEC's

[1] The current ICPA received Commission approval in Case No. 2004-00395, Application of Kentucky Utilities Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract (Ky. PSC Dec. 30, 2004); and Case No. 2004-00396, Application of Louisville Gas and Electric Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract (Ky. PSC Dec. 30, 2004).

request, that assessment has been updated since the filing of LG&E's and KU's applications.[2] The results of the updated assessment indicate that, largely due to the generating units having been nearly always operated in a base load mode, with limited thermal cycles of the equipment, the units are expected to be operational at or near their historic operating levels through the term of the ICPA extension, until mid 2040.

The assessment update also indicates that the generating facilities are expected to be in compliance with existing and pending environmental requirements. Selective catalytic reduction devices have been installed on all units over the past decade and flue gas desulfurization equipment will be installed on all units during the 2011-2013 time frame. OVEC does not expect coal combustion by-products to be regulated as a hazardous waste and, therefore, does not anticipate significant future expenditures in this area.

The proposed extension will allow LG&E and KU to continue to receive their shares of OVEC's generation in exchange for payment of OVEC's relatively low costs. As in the past, LG&E and KU will not act as guarantors of OVEC's debts nor will they issue securities or other evidence of indebtedness for the purpose of financing their participation in the Amended ICPA. However, LG&E and KU will be obligated to pay monthly minimum demand charges over the life of the amended contract. The

[2] URS Corporation performed the original assessment in 2004 and completed an update during the pendency of this proceeding.

effectiveness of the amended ICPA is contingent upon all owners receiving the necessary regulatory approvals of the states in which they operate, if applicable.[3]

The Commission, having considered the evidence of record and being otherwise sufficiently advised, finds that the energy available from OVEC is a cost-effective source of energy to LG&E and KU, and it is reasonable for LG&E and KU to secure a portion of this available energy. We further find that LG&E's and KU's participation in the OVEC contract is for lawful objects within the corporate purposes of LG&E's and KU's utility operations, is necessary and appropriate for and consistent with the proper performance of their service to the public, will not impair their ability to perform that service, is reasonably necessary and appropriate for such purposes, and should therefore be approved.

IT IS THEREFORE ORDERED that:

1. LG&E and KU are authorized to enter into the Amended Inter-Company Power Agreement among OVEC and its owners as set forth in the provisions and terms in their applications.

2. After the Amended Inter-Company Power Agreement has received all necessary regulatory approvals, LG&E and KU shall, within 20 days of the finalization of the Amended Inter-Company Power Agreement, file a copy of the agreement with the Commission.

---

[3] In addition to other state commissions, the investor-owned OVEC owners must also receive consent, or approval, of the Federal Energy Regulatory Commission.

Nothing contained herein shall be construed as a finding of value for any purpose or as a warranty on the part of the Commonwealth of Kentucky or any agency thereof as to the securities authorized herein.

By the Commission

ENTERED
PD
AUG 11 2011
KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Executive Director

Robert M Conroy
Director, Rates
Louisville Gas and Electric Company
220 W. Main Street
P. O. Box 32010
Louisville, KY 40202

Service List for Case 2011-00099

2018 IRP Reserve Margin Analysis

PPL companies

Generation Planning & Analysis

September 2018

Table of Contents

1 Executive Summary

The reliable supply of electricity is vital to Kentucky's economy and public safety, and customers expect it to be available at all times and in all weather conditions. As a result, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") have developed a portfolio of generation and demand-side management ("DSM") resources with the operational capabilities and attributes needed to reliably serve customers' year-round energy needs at a reasonable cost. In addition to the ability to serve load during the annual system peak hour, the generation fleet must have the ability to produce low-cost baseload energy, the ability to respond to unit outages and follow load, and the ability to instantaneously produce power when customers want it. While the results of this analysis are generally communicated in the context of a summer peak reserve margin, the mathematics – like past reserve margin analyses – assess the Companies' ability to reliably serve customers in all hours.

Using the same methodology as the 2014 IRP, the 2018 IRP reserve margin analysis evaluates (a) annual capacity costs and (b) annual reliability and generation production costs for 2021 over a wide range of summer peak reserve margins to identify the optimal generation mix for customers. With the Companies' existing resources, the forecasted summer peak reserve margin in 2021 is 23.5 percent in the base energy requirements forecast scenario. 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 retirement of their small-frame simple-cycle combustion turbines ("SCCTs"), the Demand Conservation Program ("DCP"), one or more Brown 11N2 SCCTs, and Brown 3.[1] Similarly, to determine if adding resources would cost-effectively improve reliability, the Companies compared the costs and benefits of adding new SCCT capacity to the generation portfolio.

The results of this analysis show that the Companies' existing resources are economically optimal for meeting system reliability needs in 2021. 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. With the exception of the DCP, the reliability and generation production cost benefit for each of the Companies' marginal resources clearly exceeds the costs that would be saved by retiring these units. Consistent with the analysis supporting the Companies' December 2017 DSM filing, the DCP is only marginally favorable. However, given uncertainties moving forward related to load and environmental regulations, and considering physical reliability guidelines, the DCP should be continued at least in the near-term.

The target summer reserve margin range established in the 2014 IRP Reserve Margin analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 loss-of-load event ("1-in-10 LOLE") physical reliability guideline. Based on the Companies' current load forecast and resources, the reserve margin required to meet this guideline is approximately 25 percent.[2] To determine the minimum of the target reserve margin range, the Companies estimated the increase in load that would result in the addition of generation resources. All

[1] The Brown 11N2 SCCTs comprise Brown 5, Brown 8, Brown 9, Brown 10, and Brown 11.

[2] The increase from 21 percent to 25 percent is driven primarily by an increase in the assumed variability of winter peak demands. The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015).

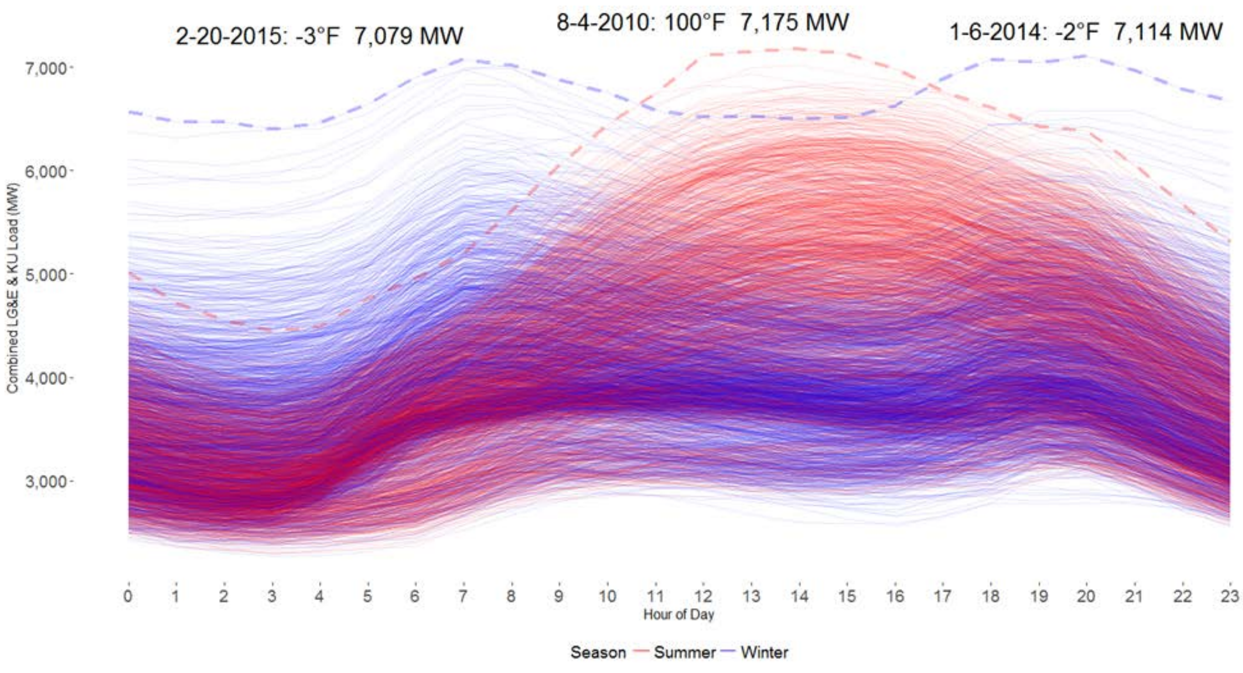
other things equal, if the Companies' load increases by 300 to 400 MW, the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. With this load increase, the Companies' reserve margin would end up being 16 to 18 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

2 Introduction

An understanding of the way customers use electricity is critical for planning a generation, transmission, and distribution system that can reliably serve customers in every moment. Temperatures in Kentucky can range from below zero degrees Fahrenheit to above 100 degrees Fahrenheit. Because of the potential for cold winter temperatures and the increasing penetration of electric heating, the Companies are somewhat unique in the fact that annual peak demands can occur in summer and winter months. The Companies' highest hourly demand occurred in the summer of 2010 (7,175 MW in August 2010). Since then, the Companies have experienced two annual peak demands in excess of 7,000 MW and both occurred during winter months (7,114 MW in January 2014 and 7,079 MW in February 2015).

Figure 1 contains the Companies' hourly load profiles for every day over the past ten years. Hourly demands can vary by as much as 600 MW from one hour to the next and by over 3,000 MW in a single day. Summer peak demands typically occur in the afternoons, while winter peaks typically occur in the mornings or evenings during nighttime hours.

Figure 1: Hourly Load Profiles, 2008-2017



System demands from one moment to the next can be almost as volatile as average demands from one hour to the next. Figure 2 contains a plot of four-second demands from 5:00 PM to 7:00 PM on January 6, 2014 during the polar vortex event. The average demand from 6:00 PM to 7:00 PM was 7,114 MW but the maximum 4-second demand was more than 150 MW higher. To serve customers in every moment, the Companies must have a portfolio of generation resources that can produce power when customers want it.

Figure 2: Four-Second Demands, 5:00-7:00 PM on January 6, 2014

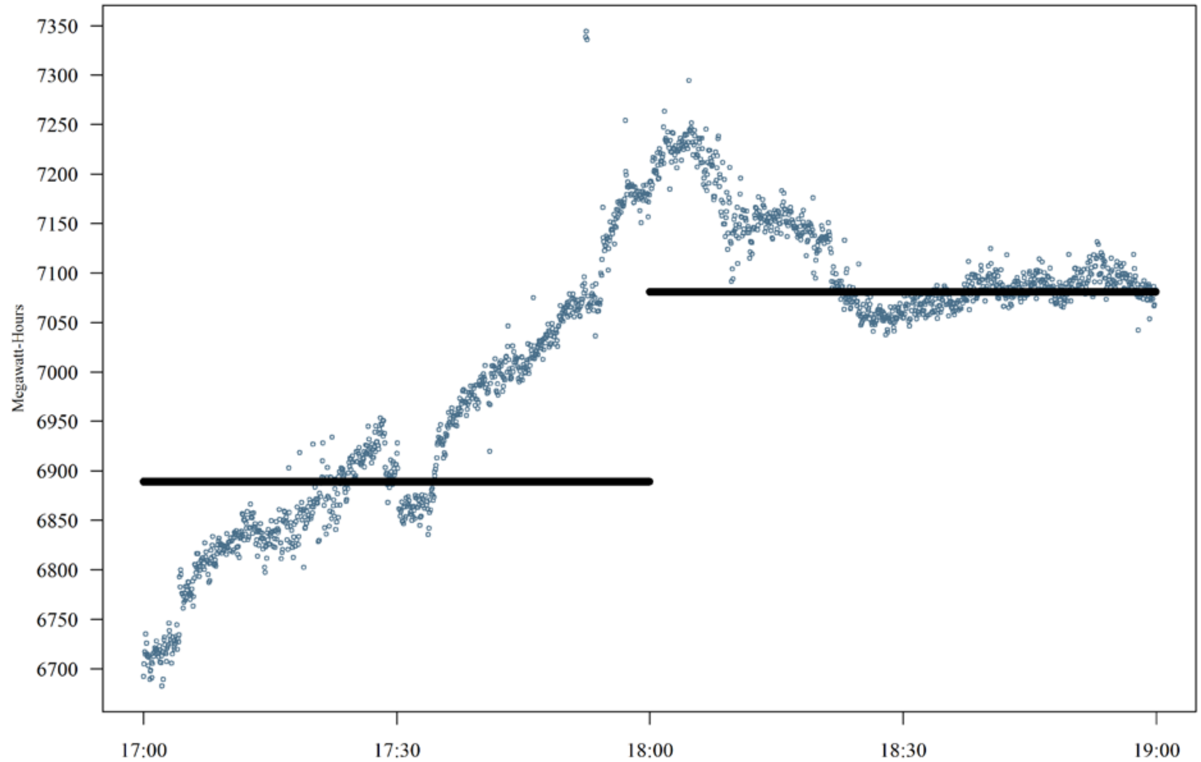


Table 1 contains the Companies' reserve margin forecast with planned retirements in the base energy requirements forecast scenario. Summer peak demand decreases from 2018 to 2019 primarily due to the departure of eight municipal customers. Load reductions associated with the Companies' DSM programs reflect changes to DSM programs approved in the Companies' recent DSM filing in Kentucky.[3] The Companies' generation capacity decreases by 437 MW in 2019 due to the planned retirement of Brown 1 and 2 (272 MW) and the expiration of the Bluegrass Agreement (165 MW), and by 14 MW in 2021 due to the planned retirement of Zorn 1, which is expected to occur within the next three years. Beginning in 2021, the forecasted reserve margin for the base energy requirements scenario ranges from 23 percent to 24 percent.

[3] *In the Matter of: Electronic Joint Application of Louisville Gas and Electric and Kentucky Utilities Company for Review, Modification, and Continuation of Certain Existing Demand-Side Management and Energy Efficiency Programs*, Case No. 2017-00441.

Table 1: Peak Demand and Resource Summary (Base Energy Requirements Forecast)

	2018	2019	2020	2021	2022	2023	2024	2027	2030	2033
Summer Peak Demand	7,028	6,703	6,688	6,674	6,657	6,653	6,638	6,655	6,650	6,627
DCP	-127	-96	-91	-87	-84	-80	-77	-67	-59	-52
DSM	-247	-247	-236	-236	-236	-236	-236	-236	-236	-236
Net Peak Demand	**6,655**	**6,360**	**6,361**	**6,350**	**6,338**	**6,338**	**6,325**	**6,352**	**6,355**	**6,339**
Existing Capability[4]	7,754	7,476	7,476	7,476	7,477	7,477	7,478	7,478	7,478	7,478
Small-Frame SCCTs	87	87	87	73	73	73	73	73	73	73
CSR	141	141	141	141	141	141	141	141	141	141
Bluegrass	165	0	0	0	0	0	0	0	0	0
OVEC[5]	152	152	152	152	152	152	152	152	152	152
Total Supply	**8,299**	**7,856**	**7,856**	**7,842**	**7,843**	**7,843**	**7,844**	**7,844**	**7,844**	**7,844**
Reserve Margin	1,644	1,495	1,495	1,491	1,505	1,505	1,518	1,492	1,489	1,505
Reserve Margin %	**24.7%**	**23.5%**	**23.5%**	**23.5%**	**23.7%**	**23.7%**	**24.0%**	**23.5%**	**23.4%**	**23.7%**

Different types of generation resources play different roles in serving customers. The Companies' coal units have real-time load-following capabilities and can be brought on-line with less than a day's notice to serve load. With higher ramp rates and shorter start times, the Companies' natural gas combined-cycle ("NGCC") unit and large-frame SCCTs can respond to significant load swings and can be committed with little notice in response to forced outages. The Companies' small-frame SCCTs and demand-side resources have no load-following capabilities; while they can be committed in response to forced outages they require more notice than large-frame SCCTs or NGCC units and their small size and high cost limit their usefulness in dealing with forced outages. Finally, the Companies' renewable resources have little to no fuel or emissions costs, but they have no load-following capabilities and their availability during peak load conditions is uncertain due to their intermittent fuel source. The Companies' resource planning decisions must ensure their generation portfolio has the full range of operational capabilities and attributes needed to serve customers in every moment.

The following sections summarize the Companies' reserve margin analysis. Section 3 discusses the analysis framework. Section 4 provides a summary of key inputs and uncertainties in the analysis. Finally, Section 5 provides a summary of the analysis results.

---

[4] Existing capability is shown excluding small-frame SCCTs, CSR, Bluegrass, and OVEC and including 1 MW derates on each of the E.W. Brown Units 8, 9, and 11, which are planned to be resolved by 2024.

[5] OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW.

3 Analysis Framework

Figure 3 illustrates the costs and benefits of adding capacity to a generation portfolio.[6] As capacity is added, reliability and generation production costs decrease (i.e., the generation portfolio becomes more reliable) but fixed capacity costs increase. In their reserve margin analysis, the Companies' evaluate these costs and benefits over a range of reserve margins. The reserve margin at which the sum of (a) capacity costs and (b) reliability and generation production costs ("total cost") is minimized is the economic reserve margin.

Figure 3: Costs and Benefits of Generation Capacity (Illustrative)

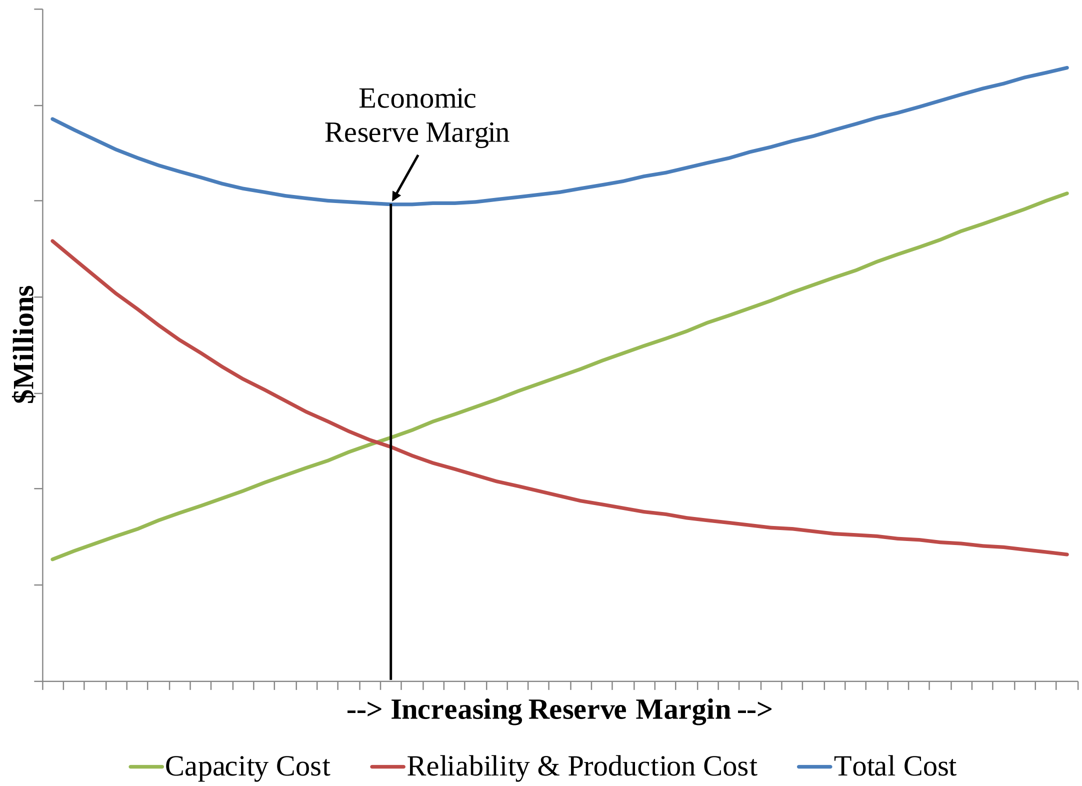
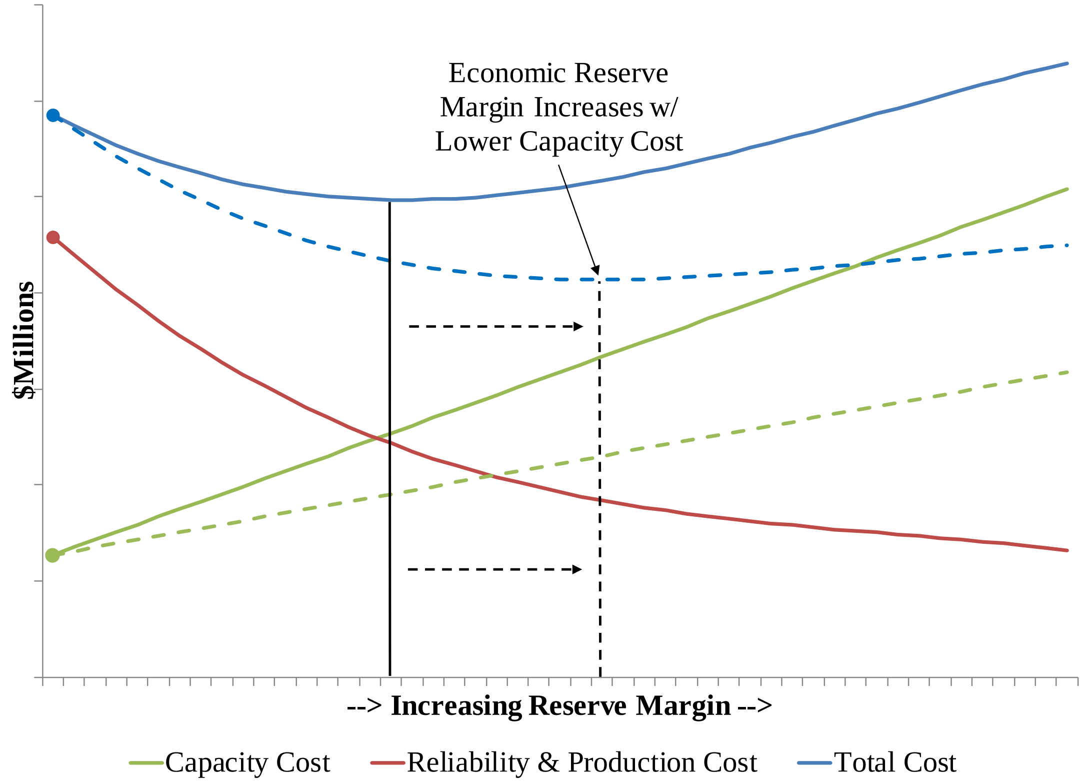


Figure 4 includes an alternative capacity cost scenario (dashed green line) for capacity with the same dispatch cost and reliability characteristics. The large dots mark the minimum of the range of reserve margins that is being evaluated. In this scenario, reliability and generation production costs are unchanged but total costs (dashed blue line) are lower and the economic reserve margin is higher. This result is not surprising; in an extreme case where the cost of capacity is zero, the Companies would add capacity until the value of adding capacity reduced to zero.[7]

[6] As mentioned previously, different types of generation resources play different roles in serving customers; not all resources provide the same reliability and generation production cost benefit.

[7] In Figure 4, as more capacity is added to the generation portfolio, the value of adding the capacity decreases (i.e., the slope of the reliability and production cost line is flatter at higher reserve margins).

Figure 4: Economic Reserve Margin and Capacity Cost (Illustrative)



For new capacity, the capacity cost includes the fixed costs required to operate and maintain the unit as well as the revenue requirements associated with constructing the unit. When a portion of the evaluated reserve margin range falls below the Companies' forecasted reserve margin, the Companies must consider the costs and benefits of retiring their existing marginal resources to evaluate this portion of the range. When contemplating the retirement of an existing resource, any unrecovered revenue requirements associated with the construction of the unit are considered sunk; the savings from retiring a unit includes only the unit's ongoing fixed operating and maintenance costs. An existing unit's ongoing fixed operating and maintenance costs are its stay-open costs.

The Companies evaluated reserve margins ranging from 12 to 24 percent in their 2014 IRP Reserve Margin Analysis. As this analysis was being developed, the Companies were evaluating the addition of Green River 5 (670 MW) at the Green River Generating Station. Without Green River 5, the Companies' reserve margin in 2018 was forecast to be 12 percent. Therefore, their reserve margin analysis evaluated only the costs and benefits of adding new capacity to their generation portfolio.

In the 2018 IRP base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. Therefore, to evaluate a similar range of reserve margins using the same methodology, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. The cost of continuing to operate each of the Companies' marginal resources is currently less than the cost of adding and operating new resources.

In North America, the most commonly used physical reliability guideline is the 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, this 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.

The Companies used the Equivalent Load Duration Curve Model ("ELDCM") and Strategic Energy Risk Valuation Model ("SERVM") to estimate reliability and generation production costs as well as the expected number of loss-of-load events in ten years ("LOLE") over a range of reserve margin levels. ELDCM estimates LOLE and reliability and generation production costs based on an equivalent load duration curve.[8] SERVM is a simulation-based model and was used to complete the reserve margin studies for the 2011 and 2014 IRPs. SERVM models the availability of generating units in more detail than ELDCM but ELDCM's simplified approach is able to consider a more complete range of unit availability scenarios. Given the differences between the models, their results should be consistent but not identical.

Key inputs to SERVM and ELDCM include load, unit availability, the ability to import power from neighboring regions, and other factors. SERVM separately models the ability to import power from each of the Companies' neighboring regions based on the availability of generation resources and transmission capacity in each region. In ELDCM, the Companies' ability to import power from neighboring regions is modeled as a single "market" resource where the availability of the resource is determined by the sum of available transmission capacity in all regions. Key analysis inputs and uncertainties are discussed in the following section.

4 Key Inputs and Uncertainties

Several factors beyond the Companies' control impact the Companies' planning reserve margin and their ability to reliably serve customers' energy needs. The key inputs and uncertainties considered in the Companies' reserve margin analysis are discussed in the following sections.

4.1 Study Year

The study year for this analysis is 2021. The municipal departure, the end of the Bluegrass Agreement, and the retirements of Brown 1 and Brown 2 are planned to occur in 2019. Zorn 1 is assumed to retire on January 1, 2021. 2021 is the first full year after these events.

4.2 Neighboring Regions

The vast majority of the Companies' off-system purchase transactions are made with counterparties in MISO, PJM, or TVA. SERVM models load and the availability of excess capacity from the portions of the MISO, PJM, and TVA control areas that are adjacent to the Companies' service territory.[9] These portions of MISO, PJM, and TVA are referred to as "neighboring regions." The following neighboring regions are modeled:

---

[8] See https://www-pub.iaea.org/MTCD/Publications/PDF/TRS1/TRS241_Web.pdf beginning at page 219 for the modeling framework employed by ELDCM.

[9] As discussed previously, the ability to import power from neighboring regions is modeled as a single "market" resource in ELDCM.

- MISO-Indiana – includes service territories for all utilities in Indiana as well as Big Rivers Electric Corporation in Kentucky.
- PJM-West – refers to the portion of the PJM-West market region including American Electric Power ("AEP"), Dayton Power & Light, Duke Ohio/Kentucky, and East Kentucky Power Cooperative service territories.
- TVA – TVA service territory.

Moving forward, uncertainty exists regarding the Companies' ability to rely on neighboring regions' markets to serve load. Approximately 20 GW of capacity was retired over the past five years in PJM and an additional 3 GW of retirements have been announced for the next five years. For the purpose of developing a target reserve margin range for long-term resource planning, reserve margins in neighboring regions are assumed to be at their target levels of 17.1% (MISO[10]), 15.8% (PJM[11]), and 15% (TVA[10]).[12]

4.3 Generation Resources

The unit availability and economic dispatch characteristics of the Companies' generating units are modeled in SERVM and ELDCM. SERVM also models the generating units in neighboring regions.

4.3.1 Unit Availability Inputs

Uncertainty related to the performance and availability of generating units is a key consideration in resource planning. Table 2 contains a summary of the Companies' generating resources along with their assumed equivalent forced outage rates ("EFORs"). The availability of units in neighboring regions was assumed to be consistent with the availability of units in the Companies' generating portfolio and not materially different from the availability of neighboring regions' units today.

---

[10] See NERC's "2018 Summer Reliability Assessment" at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf.

[11] See PJM's "2017 PJM Reserve Requirement Study" (October 12, 2017) at https://www.pjm.com/-/media/committees-groups/committees/pc/20171012/20171012-item-03a-2017-pjm-reserve-requirement-study.ashx.

[12] In the reserve margin analysis, adjustments were made to the neighboring regions' generating portfolios as needed to reflect planned retirements and meet the neighboring regions' target reserve margins.

Table 2: 2021 LG&E/KU Generating Portfolio

Resource	Resource Type	Net Max Summer Capacity (MW) [13]	EFOR
Brown 3	Coal	415	5.7%
Brown 5	SCCT	130	9.9%
Brown 6	SCCT	146	9.9%
Brown 7	SCCT	146	9.9%
Brown 8	SCCT	120	9.9%
Brown 9	SCCT	120	9.9%
Brown 10	SCCT	121	9.9%
Brown 11	SCCT	121	9.9%
Brown Solar	Solar	8	2.5%
Cane Run 7	NGCC	662	3.0%
Cane Run 11	Small-Frame SCCT	14	50.0%
Dix Dam 1-3	Hydro	32	N/A
Ghent 1	Coal	474	5.2%
Ghent 2	Coal	484	5.2%
Ghent 3	Coal	480	5.2%
Ghent 4	Coal	477	5.2%
Haefling 1-2	Small-Frame SCCT	24	50.0%
Mill Creek 1	Coal	299	5.2%
Mill Creek 2	Coal	296	5.2%
Mill Creek 3	Coal	390	5.2%
Mill Creek 4	Coal	476	5.2%
Ohio Falls 1-8	Hydro	64	N/A
OVEC-KU	Power Purchase	47	N/A
OVEC-LG&E	Power Purchase	105	N/A
Paddy's Run 11	Small-Frame SCCT	12	50.0%
Paddy's Run 12	Small-Frame SCCT	23	50.0%
Paddy's Run 13	SCCT	147	9.9%
Trimble County 1 (75%)	Coal	368	5.2%
Trimble County 2 (75%)	Coal	546	9.3%
Trimble County 5	SCCT	159	5.7%
Trimble County 6	SCCT	159	5.7%
Trimble County 7	SCCT	159	5.7%
Trimble County 8	SCCT	159	5.7%
Trimble County 9	SCCT	159	5.7%
Trimble County 10	SCCT	159	5.7%
CSR	Interruptible	141	N/A

4.3.2 Fuel Prices

The forecasts of natural gas and coal prices for the Companies' generating units are summarized in Table 3 and Table 4. Fuel prices in neighboring regions were assumed to be consistent with the Companies'

[13] Projected net ratings as of 2021. OVEC's capacity reflects the 152 MW that is expected to be available to the Companies at the time of the summer peak, not its rating of 172 MW. The ratings for Brown Solar, Dix Dam 1-3, and Ohio Falls 1-8 reflect the assumed output for these facilities during the summer peak demand. Cane Run 7 reflects the estimated impact of evaporative cooling under average summer ambient conditions.

fuel prices. The natural gas price forecast reflects forecasted Henry Hub market prices plus variable costs for pipeline losses and transportation, excluding any fixed firm gas transportation costs.

Table 3: 2021 Delivered Natural Gas Prices (LG&E and KU; Nominal $/mmBtu)

Month	Value
1	[redacted]
2	[redacted]
3	[redacted]
4	[redacted]
5	[redacted]
6	[redacted]
7	[redacted]
8	[redacted]
9	[redacted]
10	[redacted]
11	[redacted]
12	[redacted]

Table 4: 2021 Delivered Coal Prices (LG&E and KU; Nominal $/mmBtu)

Station	Value
Brown	[redacted]
Ghent	[redacted]
Mill Creek	[redacted]
Trimble County – High Sulfur	[redacted]
Trimble County – PRB	[redacted]

4.3.3 Interruptible Contracts

Load reductions associated with the Companies' Curtailable Service Rider ("CSR") are modeled as generation resources. Table 5 lists the Companies' CSR customers and their assumed load reductions. The Companies can curtail each CSR customer up to 100 hours per year.[14] However, because the Companies can curtail CSR customers only in hours when more than 10 of the Companies' large-frame SCCTs are being dispatched, the ability to utilize this program is limited to at most a handful of hours each year, and then the magnitude of load reductions depends on participating customers' load during the hours when they are called upon. The total assumed capacity of the CSR program is 141 MW.

[14] See KU's Electric Service Tariff at https://psc.ky.gov/tariffs/Electric/Kentucky%20Utilities%20Company/Tariff.pdf and LG&E's at https://psc.ky.gov/tariffs/Electric/Louisville%20Gas%20and%20Electric%20Company/Tariff.pdf.

Table 5: Interruptible Contracts

CSR Customers	Assumed Hourly Load Reduction (MW)
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
Total	140.9

4.4 Available Transmission Capacity

Available transmission capacity ("ATC") determines the amount of power that can be imported from neighboring regions to serve the Companies' load and is a function of the import capability of the Companies' transmission system as well as the export capability of the system from which the power is purchased. For example, to purchase 50 MW from PJM, the Companies' transmission system must have at least 50 MW of available import capability and PJM must have at least 50 MW of available export capability. If PJM only has 25 MW of export capability, total ATC is 25 MW.

The Companies' import capability is assumed to be negatively correlated with load. Furthermore, because weather systems impact the Companies' service territories and neighboring regions similarly, the export capability from neighboring regions is oftentimes also limited when the Companies' load is high. Table 6 summarizes the sum of daily ATC between the Companies' system and neighboring regions on weekdays during the summer months of 2016 and 2017 and the winter months of 2017 and 2018. Based on the daily ATC data, the Companies' ATC for importing power from neighboring regions is zero 45% of the time.

[15] These customers have expressed interest in the CSR but have not yet begun service under this rider.

Table 6: Daily ATC

Daily ATC Range	Count of Days	% of Total
0	95	45%
1 – 199	31	15%
200 - 399	5	2%
400 - 599	4	2%
600 - 799	10	5%
800 - 999	21	10%
>= 1,000	45	21%
Total	211	

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.

4.5 Load Modeling

Uncertainty in the amount and timing of customers' utilization of electricity is a key consideration in resource planning. Uncertainty in the Companies' load is modeled in SERVM and ELDCM. SERVM also models load uncertainty in neighboring regions. Table 7 summarizes the peak demand forecast for the Companies' service territories and neighboring regions in 2021. The Companies' peak demand is taken from the base energy requirements forecast scenario and reflects the impact of the Companies' DSM programs. The forecasts of peak demands for MISO-Indiana, PJM-West, and TVA were taken from RTO forecasts and NERC Electricity Supply and Demand data.

Table 7: Peak Load Forecasts for 2021

	LG&E/KU	MISO-Indiana	PJM-West	TVA
Peak Load	6,350	19,302	36,121	29,811
Target Reserve Margin	N/A	17.1%	15.8%	15%

The Companies develop their long-term energy requirements forecast with the assumption that weather will be average or "normal" in each month of every year. In a given month, weather on the peak day is assumed to be the average of weather on the peak day over the past 20 years. While this is a reasonable assumption for long-term resource planning, weather from one month and year to the next is never the same. The frequency and duration of severe weather events within a year have a significant impact on load shape and reliability and generation production costs. For this reason, the Companies produced 45 hourly demand forecasts for 2021 based on actual weather in each of the last 45 years.

Table 8 summarizes the distributions of summer and winter peak demands for the Companies' service territory and coincident demands in the neighboring regions. Because each set of coincident peak demands is based on weather from the same weather year, SERVM captures weather-driven covariation in loads between the Companies' service territories and neighboring regions to the extent weather is correlated.

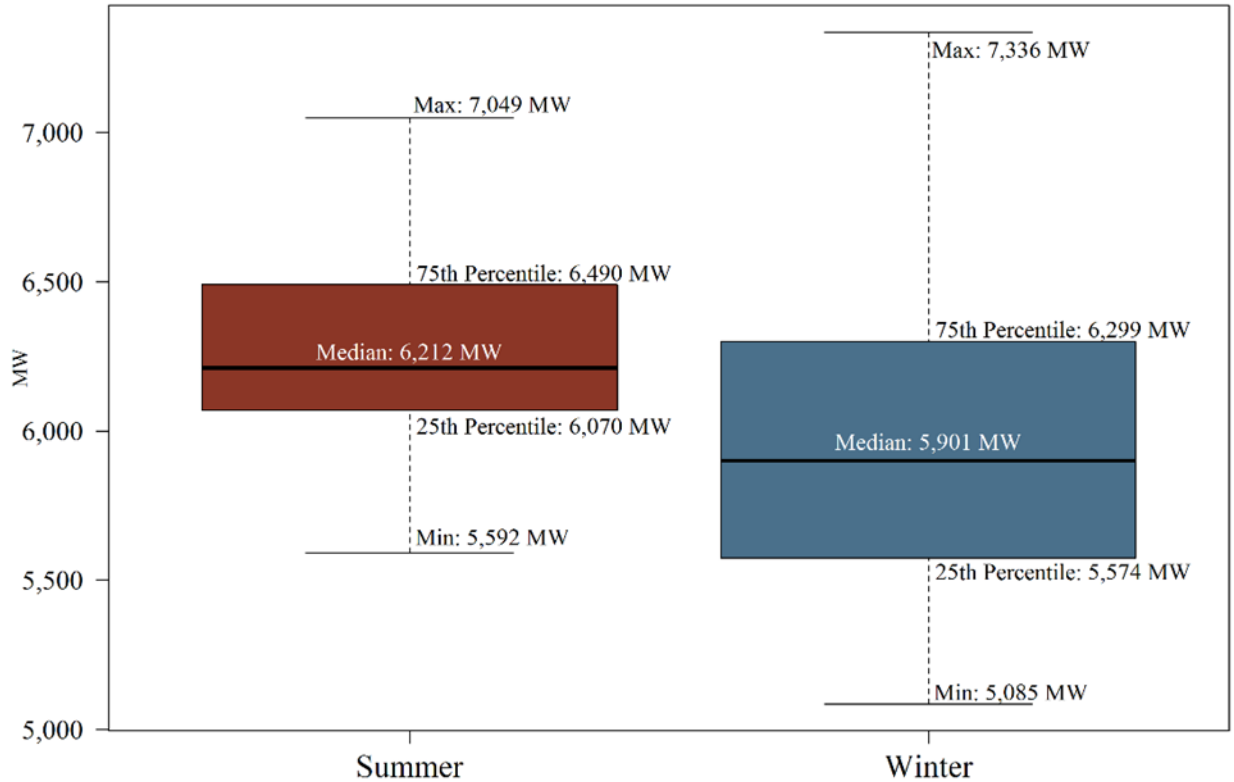
Table 8: Summer and Winter Peak Demand Forecasts

	Summer					Winter				
			Coincident Peak Demand in Neighboring Regions					Coincident Peak Demand in Neighboring Regions		
LG&E/ KU Load	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA	Weather Year	LG&E/KU	MISO-Indiana	PJM-West	TVA
Max	1983	7,049	19,880	36,987	30,648	1985	7,336	16,322	38,359	33,450
75th %-ile	2017	6,490	18,933	33,786	30,024	1986	6,299	15,840	33,667	32,181
Median	2001	6,212	17,665	32,985	27,743	2010	5,901	16,049	32,913	31,003
25th %-ile	1996	6,070	17,610	33,631	27,472	1991	5,574	15,967	34,649	26,357
Min	1974	5,592	17,509	31,742	25,109	1990	5,085	14,886	34,004	25,936

Because the ability to purchase power from neighboring regions oftentimes depends entirely on the availability of transmission capacity, load uncertainty in the Companies' service territories has a much larger impact on resource planning decisions than load uncertainty in neighboring regions. Figure 5 plots the distributions of summer and winter peak demands in the Companies' service territories. The Companies' median peak demand is higher in the summer, but the variability in peak demands – as experienced over the past five years – is much higher in the winter.[16] This is largely due to the fact that electric heating systems with heat pumps consume significantly more energy during extreme cold weather when the need for backup resistance heating is triggered.

[16] The distributions in Table 8 do not reflect load reductions associated with the Companies' Curtailable Service Rider ("CSR") because this program is modeled as a generation resource; CSR load reductions are forecast to be 141 MW in 2021. The maximum winter peak demand (7,336 MW) is forecasted based on the weather from January 20, 1985 when the average temperature was -8 degrees Fahrenheit and the low temperature was -16 degrees Fahrenheit. For comparison, the Companies' peak demand on January 6, 2014 during the polar vortex event was 7,114 MW and the average temperature was 8 degrees Fahrenheit and the low temperature was -3 degrees Fahrenheit. CSR customers were curtailed during this hour and the departing municipals' load was 285 MW.

Figure 5: LG&E and KU Peak Demands, 2021



4.6 Marginal Resource Costs

In the base energy requirements forecast, the Companies' forecasted reserve margin in 2021 is 23.5 percent. To evaluate reliability and cost at lower and higher reserve margins, the Companies evaluated the retirement of existing marginal resources as well as the addition of new resources. Furthermore, because different types of resources have different operating capabilities, the Companies separately evaluated the retirement of marginal baseload and marginal peaking resources.

Table 9 contains stay-open costs (i.e., ongoing fixed operating and maintenance costs) and average energy costs for the Companies' baseload generation units that are 40 or more years old, the Companies' peaking units that are 15 or more years old, and the Companies' Demand Conservation Programs ("DCP").[17] The Companies' peaking units include large-frame and small-frame SCCTs; small-frame SCCTs include Haefling 1 and 2, Paddy's Run 11 and 12, and Cane Run 11. The stay-open costs in Table 9 are presented in 2021 dollars and are computed based on stay-open costs over an eight-year

[17] The Demand Conservation Programs include the Residential and Non-Residential Demand Conservation Programs. These programs are the Companies' only dispatchable demand-side management programs. The Companies did not evaluate the Curtailable Service Rider because the elimination of this rider would have no impact on total revenue requirements.

maintenance cycle from 2020 to 2027.[18] Similar peaking units (e.g., Brown 5, 8, 9, 10, & 11) are grouped together. Average energy costs are computed based on the base fuel prices in Section 4.3.2.

Table 9: Marginal Resource Costs (2021 Dollars)

	Resource	Stay-Open Cost ($/kW-year)	Average Energy Cost ($/MWh)	Stay-Open Costs + Average Energy Costs ($/MWh)
Baseload	Brown 3	87.3	34	84
	Ghent 1	84.1	24	41
	Ghent 2	65.1	22	32
	Mill Creek 1	71.3	23	35
	Mill Creek 2	81.0	23	37
	Mill Creek 3	78.0	24	37
	OVEC	92.3	25	47
Peaking	Brown 5, 8, 9, 10, & 11	11.5	41	79
	Brown 6 & 7	20.5	31	66
	Paddy's Run 13	16.3	30	52
	Trimble County 5 & 6	29.7	30	64
	Small-Frame SCCTs	3.4	80	406
DSM	Demand Conservation Programs ("DCP")	25.6	145	460

To evaluate reserve margins less than 23.5 percent, the sum of stay-open and average energy costs in Table 9 was used to determine the order in which certain baseload and peaking resources would be considered for retirement. For example, based on these costs, the Companies assumed that the DCP would be retired first and the small-frame SCCTs would be retired second. The annual stay-open costs for these resources (expressed on a $/kW-year basis) are not as high as other resources, but the sums of stay-open and average energy costs (expressed on a $/MWh basis) are much higher due to their high dispatch cost which results in limited utilization. In addition, customer participation in the DCP is expected to decline moving forward and the small-frame SCCTs are far more likely to experience a catastrophic failure because of their age.[19] It would not be prudent to retire another unit with the assumption that these resources could be more heavily utilized.

Based on the sum of stay-open and average energy costs in Table 9, Brown 3 ("BR3") and OVEC are the Companies' marginal baseload units and, besides the small-frame SCCTs, Brown 5, 8, 9, 10, and 11 ("BR5, BR8, BR9, BR10, and BR11") are the Companies' marginal peaking units. The stay-open cost for Brown 3 is consistent with other baseload units but its average generation cost is higher primarily due to

[18] An example of this calculation is included in Appendix A: Stay-Open Cost Example.
[19] The Companies do not plan for major maintenance on their small-frame SCCTs. These units range between 48 and 50 years old, have relatively inefficient heat rates compared to large-frame SCCTs, and are only operated on a limited basis.

the high cost of rail transportation for coal delivered to the Brown station. Despite this fact, the ability to shift generation to Brown 3 from other coal units is a valuable alternative for controlling fleet-wide emissions.[20]

To evaluate reserve margins greater than 23.5 percent, the analysis weighed the costs and benefits of adding new SCCT capacity. The cost of new SCCT capacity is taken from the 2018 IRP Resource Screening Analysis and is summarized in Table 10 in 2021 dollars. Not surprisingly, the carrying charge for new SCCT capacity ($123/kW-year) is higher than the stay-open costs for existing capacity ($3-92/kW-year) since their construction cost is considered sunk.

Table 10: SCCT Cost (2021 Dollars)[21]

Input Assumption	**Value**
Capital Cost ($/kW)	964.5
Fixed Charge Rate	9.0%
Fixed O&M ($/kW-yr)	13.3
Firm Gas Transport ($/kW-yr)	23.6
Carrying Charge ($/kW-yr)	123.3

4.7 Cost of Unserved Energy (Value of Lost Load)

The impacts of unserved energy on business and residential customers include the loss of productivity, interruption of a manufacturing process, lost product, potential damage to electrical services, and inconvenience or discomfort due to loss of cooling, heating, or lighting.

For this study, unserved energy costs were derived based on information from four publicly available studies.[22] All studies split customers into residential, commercial, and industrial classes which is a typical breakdown of customers in the electric industry. After escalating the costs from each study to 2021 dollars and weighting the cost based on LG&E and KU customer class weightings across all four studies, the cost of unserved energy was calculated to be $18.30/kWh.

---

[20] Brown 3 has been retrofitted with flue-gas desulfurization equipment designed to remove 98% of the unit's sulfur dioxide emissions, selective catalytic reduction designed to remove 90% of the unit's emissions of nitrogen oxides, a fabric filter baghouse designed to remove 99.5% of the unit's particulate matter, and an overall air quality control system designed to achieve 89% mercury removal.

[21] Source: NREL's 2018 ATB (https://atb.nrel.gov/). The Companies inflated NREL's cost forecasts, which were provided in real 2016 dollars, to nominal dollars at 2% annually.

[22] "Estimated Value of Service Reliability for Electric Utility Customers in the Unites States," Ernest Orlando Lawrence Berkeley National Laboratory, June 2009;
"Assessment of Other Factors: Benefit-Cost Analysis of Transmission Expansion Plans," Christensen Associates Energy Consulting, August 15, 2005;
"A Framework and Review of Customer Outage Costs: Integration and Analysis of Electric Utility Outage Cost Surveys," Ernest Orlando Lawrence Berkeley National Laboratory, November 2003;
"Value of Lost Load," University of Maryland, February 14, 2000.

Table 11 shows how the numbers were derived. The range for residential customers varied from $1.40/kWh to $3.50/kWh. The range for commercial customers varied from $24.70/kWh to $36.60/kWh while industrial customers varied from $12.80/kWh to $29.70/kWh. Not surprisingly, commercial and industrial customers place a much higher value on reliability given the impact of lost production and/or product. The range of system cost across the four studies is approximately $7.50/kWh.

Table 11: Cost of Unserved Energy (2021 Dollars)

	Customer Class Mix	2003 DOE Study $/kWh	2009 DOE Study $/kWh	Christian Associates Study $/kWh	Billinton and Wacker Study $/kWh
Residential	34%	1.60	1.40	3.50	3.00
Commercial	36%	36.60	33.30	24.70	25.70
Industrial	30%	21.10	29.70	12.80	25.70
System Cost of Unserved Energy		20.10	21.40	13.90	18.00
	Customer Class Mix	**Min $/kWh**	**Mean $/kWh**	**Max $/kWh**	**Range $/kWh**
Residential	34%	1.40	2.40	3.50	2.10
Commercial	36%	24.70	30.10	36.60	11.90
Industrial	30%	12.80	22.30	29.70	16.90
Average System Cost of Unserved Energy			18.30		

4.8 Spinning Reserves

Based on the Companies' existing resources, they are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation and comply with NERC standards. The reserve margin analysis assumes the Companies would shed firm load in order to maintain their spinning reserve requirements.

4.9 Reserve Margin Accounting

The following formula is used to compute reserve margin:

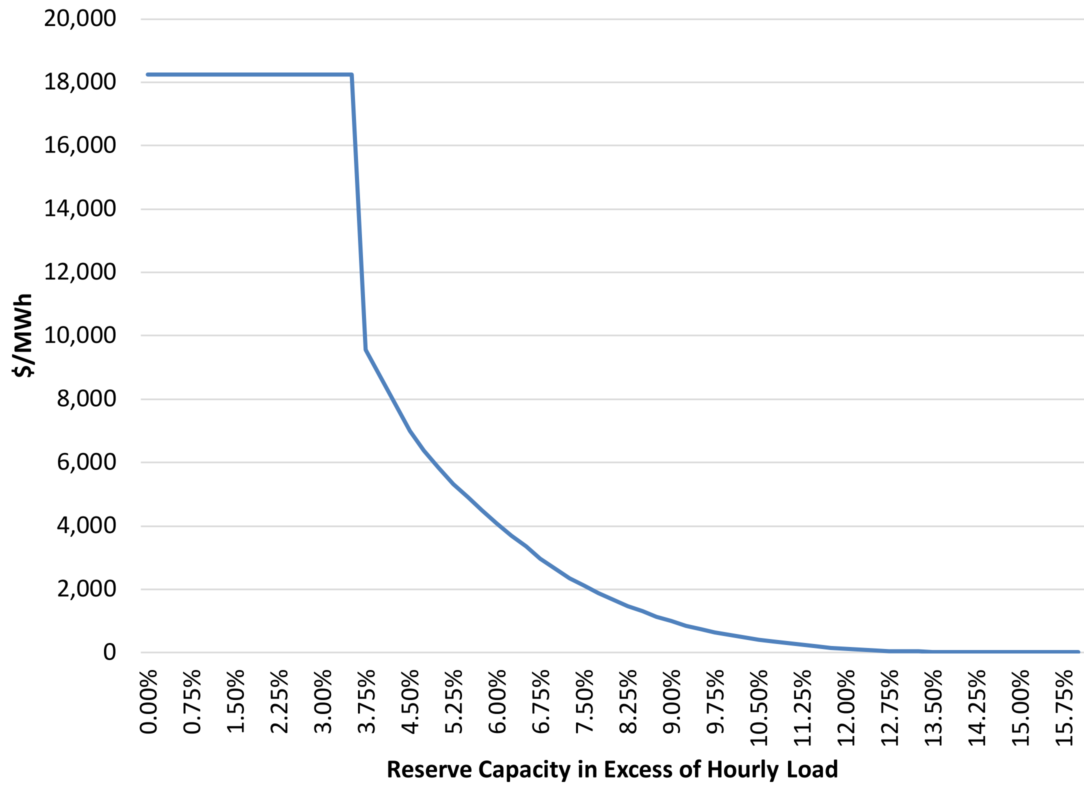
Reserve Margin = Total Supply/Peak Demand Forecast – 1

Total supply includes the Companies' generating resources and interruptible contracts. 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. While the Companies are assumed to carry 251 MW of spinning reserves to meet their reserve sharing obligation, this obligation is not included in the peak demand forecast nor as a reduction in generation resources for the purpose of computing reserve margin.

4.10 Scarcity Pricing

As resources become scarce, the price for market power begins to exceed the marginal cost of supply. The scarcity price is the difference between market power prices and the marginal cost of supply. Figure 6 plots the scarcity pricing assumptions in SERVM. The scarcity price is a function of reserve capacity in a given hour and is added to the marginal cost of supply to determine the price of purchased power. The Companies' assumed spinning reserve requirement (251 MW) is approximately 3.5% of the forecasted summer peak demand in 2021 (6,350 MW). At reserve capacities less than 3.5% of the hourly load, the scarcity price is equal to the Companies' value of unserved energy ($18,250/MWh; see Section 4.7). The remainder of the curve is estimated based on market purchase data.

Figure 6: Scarcity Price Curve



The scarcity price impacts reliability and generation production costs only when generation reserves become scarce and market power is available. In ELDCM, the scarcity price is specified as a single value and is approximately $55/MWh. Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities.

4.11 Summary of Scenarios

Reliability costs and loss-of-load events occur when loads are high or when supply is limited. To properly capture the cost of high-impact, low-probability events, the Companies evaluate thousands of scenarios that encompass a wide range of weather, load, and unit availability scenarios.

5 Analysis Results

5.1 Economic Reserve Margin and 1-in-10 LOLE Guideline

The Companies' forecasted reserve margin in 2021 is 23.5 percent in the base energy requirements forecast. Consistent with the methodology used in the 2014 IRP reserve margin analysis, the Companies estimated the sum of (a) annual capacity costs and (b) annual reliability and generation production costs over reserve margins ranging from 13 percent to 26 percent to identify the optimal generation mix for customers. To evaluate operating at lower reserve margins with less reliability, the Companies evaluated the retirement of its existing baseload and peaking resources. To determine if adding resources would cost-effectively improve reliability, the Companies evaluated the addition of new SCCT capacity. The generation portfolios evaluated in this analysis are described in Table 12. As discussed previously, the DCP and small-frame SCCTs are always assumed to be retired before other resources.

Table 12: Generation Portfolios Considered in Reserve Margin Analysis

Generation Portfolio	Portfolio Abbreviation	Reserve Margin
Add 140 MW of SCCT capacity to Existing portfolio	Add SCCT2	25.7%
Add 70 MW of SCCT capacity to Existing portfolio	Add SCCT1	24.6%
Existing (includes retirements of Brown 1, Brown 2, and Zorn 1)	Existing	23.5%
Retire DCP	Ret DCP	21.7%
Retire DCP, small-frame SCCTs	Ret DCP_SF	20.6%
Retire DCP, small-frame SCCTs, Brown 8	Ret B8*	18.7%
Retire DCP, small-frame SCCTS, Brown 8-9	Ret B8-9*	16.9%
Retire DCP, small-frame SCCTS, Brown 8-10	Ret B8-10*	15.0%
Retire DCP, small-frame SCCTS, Brown 8-11	Ret B8-11*	13.1%
Retire DCP, small-frame SCCTS, Brown 3	Ret B3*	14.2%

*Portfolio also includes retirement of DCP and small-frame SCCTs.

LOLE as well as reliability and generation production costs were evaluated in SERVM and ELDCM for each generation portfolio in Table 12 over 45 weather year scenarios and hundreds of unit availability scenarios. Table 13 contains for each portfolio the average LOLE from ELDCM as well as the annual sum of (a) capacity costs and (b) reliability and generation production costs ("total cost"). The same results from SERVM are summarized in Table 14. Portfolios with LOLE greater than five (i.e., five times the 1-in-10 LOLE physical reliability guideline) are highlighted in gray. These portfolios are not considered viable based on their poor reliability. Capacity costs for each generation portfolio are presented as the difference between the portfolio's capacity cost and the capacity cost for the Ret B3* portfolio. Total costs are estimated based on average ("Avg") reliability and generation production costs as well as the 85^{th} and 90^{th} percentiles ("%-ile") of the reliability and generation production cost distribution.

Table 13: Reserve Margin Analysis Results (ELDC Model, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year) [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year) [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.9	55.7	765	781	790	821	837	846
Add SCCT1	24.6%	1.2	47.1	766	782	791	813	829	838
Existing	23.5%	1.6	38.5	767	783	793	805	821	831
Ret DCP	21.7%	1.7	36.1	767	783	793	803	819	829
Ret DCP_SF	20.6%	2.0	35.9	768	783	794	803	819	830
Ret B8*	18.7%	2.9	34.4	770	789	799	805	824	833
Ret B8-9*	16.9%	4.3	33.0	775	799	806	808	832	839
Ret B8-10*	15.0%	6.3	31.6	781	812	822	813	844	854
Ret B8-11*	13.1%	9.0	30.2	790	829	843	820	859	873
Ret B3*	14.2%	7.4	0.0	784	817	832	784	817	832

*Portfolio also include retirement of DCP and small-frame SCCTs.

Table 14: Reserve Margin Analysis Results (SERVM, 2021 Dollars)

Generation Portfolio	2021 Reserve Margin	LOLE	[A] Capacity Cost ($M/year)	Reliability and Generation Production Costs ($M/year) [B] Avg	[C] 85th %-ile	[D] 90th %-ile	Total Cost: Capacity Costs + Reliability and Generation Production Costs ($M/year) [A]+[B] Avg	[A]+[C] 85th %-ile	[A]+[D] 90th %-ile
Add SCCT2	25.7%	0.7	55.7	771	790	796	827	846	852
Add SCCT1	24.6%	1.0	47.1	771	793	797	818	840	844
Existing	23.5%	1.4	38.5	771	789	798	809	827	836
Ret DCP	21.7%	1.5	36.1	771	790	800	807	826	836
Ret DCP_SF	20.6%	1.8	35.9	772	792	801	808	828	837
Ret B8*	18.7%	2.6	34.4	773	796	805	807	831	839
Ret B8-9*	16.9%	3.8	33.0	775	808	814	808	841	847
Ret B8-10*	15.0%	5.8	31.6	780	815	819	812	847	850
Ret B8-11*	13.1%	8.5	30.2	788	833	844	819	863	874
Ret B3*	14.2%	8.3	0.0	791	837	843	791	837	843

*Portfolio also include retirement of DCP and small-frame SCCTs.

The results from ELDCM and SERVM are entirely consistent. The ranking of portfolios based on LOLE is the same in both models. Based on ELDCM, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is between 24.6 percent and 25.7 percent. Based on SERVM, this guideline is met with a 24.6 percent reserve margin. Considering the portfolios with LOLE less than five, when reliability and generation production costs are evaluated based on the average, 85th percentile, or 90th percentile of the distribution, the Existing and Ret DCP portfolios have the lowest total cost.

Beginning in 2019, the Companies will operate the Demand Conservation Programs in "maintenance" mode, allowing new participants to enroll in the program only to the extent existing devices are available to deploy. In addition, the Companies will reduce the annual incentive to $5 and pay participating customers only in years in which a Load Control Event is called. This analysis assumes customer participation will decline by almost 30 percent by 2021 as a result of these changes, but any actual change in customer participation is uncertain.

Additionally, the Companies face other uncertainties that impact resource planning decisions:

- Three of the Companies' coal units are not retrofitted with selective catalytic reduction ("SCR") so future changes to National Ambient Air Quality Standards may require one or more of the following actions in the next three to seven years: investment to further reduce emissions of nitrogen oxides ("NO_x"), changes in plant operations during ozone season, unit retirements, and acquisition of new generation.
- The U.S. Environmental Protection Agency ("EPA") recently proposed the Affordable Clean Energy Rule ("ACE Rule") which would establish guidelines for states to regulate carbon dioxide ("CO_2") emissions from existing fossil fuel-based electric generating units.[23] At a minimum, due to the regulatory timeline, fleet-specific and unit-specific planning for the ACE Rule is uncertain for the next two to four years.
- Lastly, as discussed in Section 5.(3) of Volume I, upside and downside uncertainty exists in the Companies' energy requirements forecast.

Given these uncertainties and the small differences in total costs between the Existing and Retire DCP portfolios, the Companies are not proposing to discontinue the DCP at this time. Instead, they will continue to the monitor participation in the DCP program and other regulatory and load developments to more holistically consider potentially broader changes to their generation mix in the future.

Consistent with the 2014 IRP reserve margin analysis, the Companies estimated total costs based on the 85th and 90th percentiles of the reliability and generation production cost distribution to consider the potential volatility in total costs for customers. For example, compared to the Existing portfolio and considering the results from both models, average annual reliability and generation production costs for the Ret B3* portfolio are $17 million to $20 million higher, but the Companies would expect these costs to be $39 million to $45 million higher once in ten years (90th percentile of distribution). With Brown 3 in the generation portfolio, the portfolio is far more reliable and reliability and generation production costs are significantly less volatile.

[23] EPA is proposing to exempt SCCT and NGCC units from the ACE Rule, subject to public comments.

5.2 Target Reserve Margin Range

The target reserve margin range established in the 2014 IRP Reserve Margin Analysis was 16 to 21 percent. In that analysis, the high end of the range (21 percent) was the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline. Based on the Companies' current load forecast and resource mix, the reserve margin required to meet the 1-in-10 physical reliability guideline is approximately 25 percent (see Table 13 and Table 14). This increase is explained primarily by changes in the load forecast, which – consistent with recent history – assumes greater variability in winter peak demands (see Figure 5). The reserve margin analysis for the 2014 IRP was completed in 2013 and did not consider the possibility of the winter peak demands exceeding 7,000 MW (as experienced in 2014 and 2015). The increased variability in winter peak demands is primarily the result of increasing penetrations of electric heating in the Companies' service territories.

For the minimum of the target reserve margin range, the Companies estimated the change in load that would require the addition of generation resources. Specifically, the Companies estimated the load increase that would cause the Add SCCT1 portfolio to be less costly than the Existing portfolio. The reserve margin associated with this increase is the minimum of the reserve margin range. Below this range, the Companies should seek to acquire additional resources to avoid reliability falling to levels that would likely be unacceptable to customers.

Because significant near-term load increases are most likely to be the result of the addition of one or more large industrial customers, the analysis evaluated the addition of large, high load factor loads.[24] The results of this analysis from ELDCM and SERVM are summarized in Table 15 and Table 16, respectively. Consistent with the 2014 IRP reserve margin analysis, this analysis is focused on total costs that are estimated based on the 85th and 90th percentiles of the reliability and generation production cost distribution for the purpose of reducing volatility for customers. With no change in the load, total costs for the Existing and Add SCCT1 portfolios are the same as in Table 13 and Table 14. Based on ELDCM and assuming all other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. The results from SERVM are very similar.

[24] Not all industrial loads have high load factors. In practice, significant load changes would have to be evaluated on a case-by-case basis to ensure reliable supply.

Table 15: Minimum of Target Reserve Margin Range (ELDC Model)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	821	829	8	831	838	7
50	22.5%	833	841	8	844	851	7
100	21.6%	845	853	7	857	864	6
150	20.6%	859	865	6	871	876	6
200	19.7%	874	877	4	885	890	5
250	18.8%	890	892	2	899	903	4
300	17.9%	907	908	1	914	918	3
350	17.0%	925	925	(1)	931	933	2
400	16.2%	943	942	(1)	949	949	0

Table 16: Minimum of Target Reserve Margin Range (SERVM)

Load Change	Reserve Margin for Existing Portfolio	Total Cost w/ 85th %-ile Reliability and Production Costs ($M/year)			Total Cost w/ 90th %-ile Reliability and Production Costs ($M/year)		
		Existing	Add SCCT1	Diff: Add SCCT1 less Existing	Existing	Add SCCT1	Diff: Add SCCT1 less Existing
0	23.5%	827	840	13	836	844	8
50	22.5%	840	847	7	851	855	4
100	21.6%	852	863	11	864	869	4
150	20.6%	866	875	8	879	882	3
200	19.7%	883	886	4	896	897	1
250	18.8%	900	899	0	913	913	0
300	17.9%	914	918	4	925	930	6
350	17.0%	932	934	2	947	945	(3)
400	16.2%	955	950	(5)	964	963	(1)

5.3 Sensitivity Analysis

The inputs to the reserve margin analysis are detailed in Section 4. Because several of these inputs are uncertain, the Companies evaluated several sensitivities to the base case inputs. Table 17 lists the least-cost generation portfolios for each sensitivity, considering portfolios with LOLE less than five. As demonstrated in Section 5.1, the total cost of the Retire DCP portfolio is slightly lower than the total cost of the Existing portfolio in the base case scenario. The Companies used ELDCM to evaluate sensitivities to the cost of unserved energy, scarcity prices, EFOR, and ATC.

Table 17: Sensitivity Analysis (Least-Cost Generation Portfolio)

Case	85th Percentile	90th Percentile
Base Case	Ret DCP	Ret DCP
Cost of Unserved Energy		
25% Higher Cost of Unserved Energy ($22,800/MWh)	Ret DCP	Ret DCP
25% Lower Cost of Unserved Energy ($13,700/MWh)	Ret DCP	Ret DCP
Scarcity Prices		
25% Higher Scarcity Prices	Ret DCP	Ret DCP
25% Lower Scarcity Prices	Ret DCP	Ret DCP
Unit Availability		
Increase EFOR by 1.5 Points	Existing	Ret DCP
Decrease EFOR by 1.0 Points	Ret DCP	Ret DCP
Available Transmission Capacity		
No Access to Neighboring Markets	Ret DCP	Existing
High ATC (1,000 MW of ATC During Peak Hours)	Ret DCP	Ret DCP

5.4 Final Recommendation

All other things equal, if the Companies' load increases by 300 to 400 MW (i.e., reserve margin decreases to 16 to 18 percent), the reliability and production cost benefits from adding new SCCT capacity would more than offset the cost of the capacity. Furthermore, the reserve margin required to meet the 1-in-10 LOLE physical reliability guideline is approximately 25 percent. Therefore, based on reliability guidelines and the cost of new capacity, the Companies will target a reserve margin range of 17 to 25 percent for resource planning.

6 Appendix A: Stay-Open Cost Example

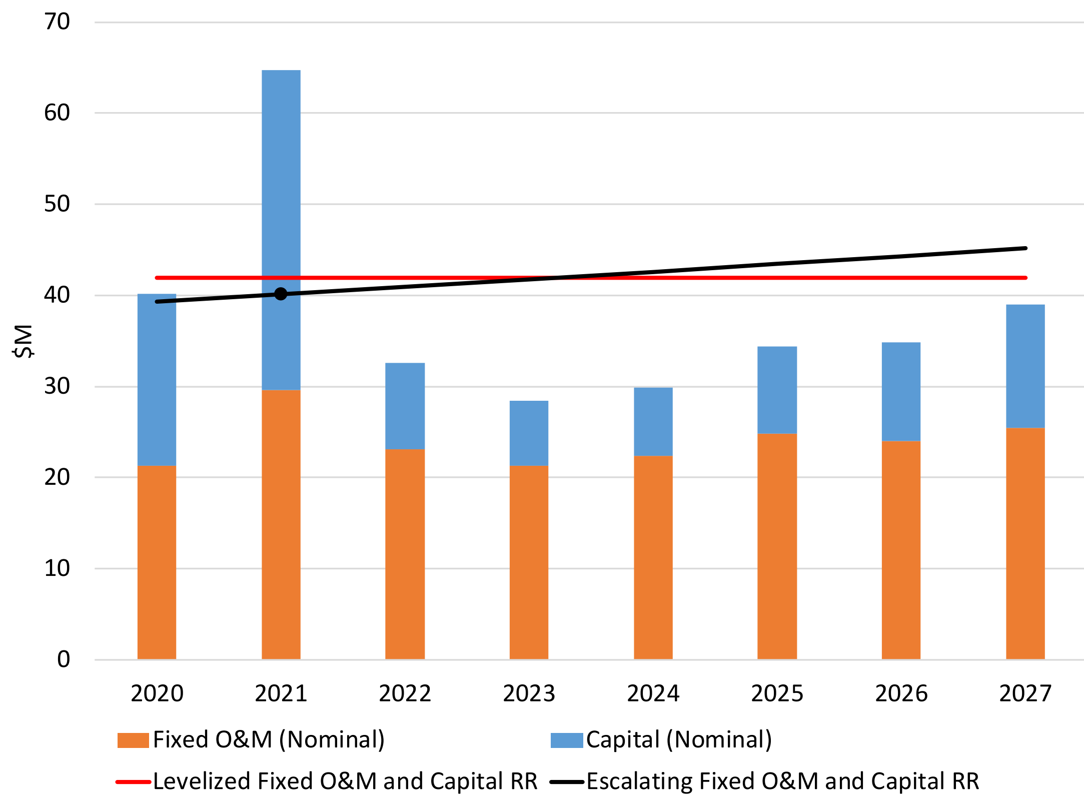
Table 18 contains capital and fixed O&M expenses for Ghent 1 over a typical 8-year maintenance cycle. With the exception of 2021 when the unit is scheduled for a turbine overhaul, fixed O&M is fairly consistent; several components of fixed O&M are assumed to grow at constant escalation rates. Capital costs are also highest in 2021 and more consistent in other years.

Table 18: Ghent 1 Capital and Fixed O&M (Nominal $M)

	2020	2021	2022	2023	2024	2025	2026	2027
Capital	18.8	35.1	9.5	7.1	7.5	9.6	10.8	13.6
Fixed O&M	21.3	29.6	23.1	21.3	22.3	24.9	24.0	25.4

To compute a stay-open cost for each marginal unit in 2021 dollars, the Companies levelized each unit's capital and fixed O&M expenses over the unit's maintenance cycle and adjusted the levelized capital cost to reflect the cost's impact on annual revenue requirements. Then, they converted the levelized cost stream into an escalating stream over the same period such that the levelized and escalating streams have the same present value of revenue requirements. In the escalating stream, costs are assumed to escalate at two percent per year. Figure 8 plots the result of this process for Ghent 1. The levelized cost is $41.9 million. The escalating cost is $40.1 million in 2021 and increases from $39.3 million in 2020 to $45.2 million in 2027.

Figure 7: Ghent 1 Stay-Open Costs



LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 14

Responding Witness: Stuart A. Wilson

Q-14. Reference Volume I of the Companies' 2021 IRP.

a. Reference Table 5-7. Identify/define which hours of the day are "night hours."

b. Reference Table 5-16. Explain how the "Contribution to Summer Peak," "Contribution to Winter Peak," and "Net Capacity Factors," were each calculated. Identify the data sources and assumptions used in each of these calculations, and provide the executable version (e.g., Excel file) of these calculations.

A-14.

a. Night hours vary by month and day. See the third tab of the attachment to response to JI 1-60.

b. The "Contribution to Summer Peak" and "Contribution to Winter Peak" are computed as the average of summer- and winter-month availability factors for each technology and are based on the analysis summarized in Exhibit DSS-2 to David S. Sinclair's Supplemental Direct Testimony in Case Nos. 2020-00349 and 2020-00350 (see Table 8 of attachment). As explained in the response to PSC 7-34 in the aforementioned cases, the monthly availability factor for each technology is the technology's average capacity factor in the mode peak hour (i.e., the hour in which the peak most commonly occurred over the past 20 years). See attachments being provided in Excel format. The "Net Capacity Factors" are consistent with NREL's 2021 ATB as indicated in footnote 38.

Avoided Capacity Cost

For a given technology and contract term, an avoided capacity price (in $/MWh) is computed as a function of the Companies' future need for generation capacity and the cost of avoided capacity. Each of these items and the method for computing levelized costs for tariff purposes are discussed in the following sections.

1 Future Need for Generation Capacity

The Companies' need for future generation capacity depends on load growth and the timing of generating unit retirements. As discussed in Supplemental Exhibit DSS-1, the 2021 BP assumed that Mill Creek Unit 1 would be retired without replacement in 2024, and Mill Creek Unit 2 ("MC2") and Brown Unit 3 ("BR3") would be retired in 2028. Given the uncertainty associated with future environmental regulations, the timing of the MC2 and BR3 retirements is uncertain. Therefore, the Companies computed the future need for generating capacity as the average of two retirement scenarios. In the first scenario, MC2 and BR3 are assumed to be retired in 2028, consistent with the Companies' 2021 BP. In the second scenario, MC2 and BR3 are assumed to be retired in 2034 and 2035, respectively, at the end of their depreciable lives. In both scenarios, all other generating units were assumed to be retired at the end of their depreciable lives.

Table 1 summarizes the Companies' summer capacity need in each scenario as well as the average summer capacity need. Table 15 and Table 16 in Appendix A provide a detailed summary of the Companies' summer peak demand forecast, unit retirement assumptions, and summer capacity need for each scenario.

Table 1: Summer Capacity Need (MW)

Year	Scenario 1: 2021 BP	Scenario 2: End of Depreciable Life	Average of Scenarios 1 and 2
2022	0	0	0
2023	0	0	0
2024	0	0	0
2025	0	0	0
2026	0	0	0
2027	0	0	0
2028	199	0	100
2029	188	0	94
2030	173	0	87
2031	160	0	80
2032	152	0	76
2033	154	0	77
2034	1,230	818	1,024
2035	1,473	1,473	1,473
2036	1,595	1,595	1,595
2037	2,556	2,556	2,556
2038	2,561	2,561	2,561
2039	3,723	3,723	3,723
2040	3,876	3,876	3,876
2041	4,184	4,184	4,184
2042	4,658	4,658	4,658
2043	4,739	4,739	4,739
2044	5,214	5,214	5,214
2045	5,650	5,650	5,650

2 Avoided Capacity Cost

The Companies used two methods to compute avoided capacity costs:

1. Current Market Price
2. Levelized Cost of a Simple Cycle Combustion Turbine (“CT”)

Because generating technologies have different energy performance capabilities, the Companies used both of these methods to develop avoided capacity costs for the following technologies:

1. single axis tracking solar,
2. fixed tilt solar,
3. wind,
4. other technologies (e.g., cogeneration facility with a steam host, hydro, biomass).

Due to a lack of market data, only the Levelized Cost of a CT method was used for the “other technology” category.

The Current Market Price method uses technology specific PPA prices to directly calculate annual avoided capacity prices. This is done by subtracting each technology's avoided energy cost from the PPA price.[1] While this difference is not really the value of capacity, the only reason that customers should be willing to pay more than avoided energy cost is because they see some additional value from the PPA. For the purposes of this method, that value is assumed to be capacity.

The Levelized Cost of a CT method starts first by determining the annual economic carrying charge of an investment in a new CT. Because a CT is available to meet peak load in each month, the Levelized Cost of a CT method requires adjusting the annual capacity cost of a CT by each technology's ability to meet monthly peak. If this adjustment was not made, customers would be overpaying for capacity in certain months. Once each technology's annual capacity cost is determined, this value is converted to a $/MWh avoided capacity cost by dividing the annual capacity payment by each technology's annual energy production.

After avoided capacity costs are determined for each method, the least-cost method was selected to calculate the avoided capacity payment for each technology by zeroing out any values in a year when there is no capacity need. These annual values are then levelized in order to determine the final 2-year and 20-year avoided capacity payments.

2.1 Current Market Price

Ideally, market prices should be based on current transactions. However, when markets are thinly traded or volatile, it can be necessary to average transactions to get a better sense of market prices. The Companies have one recent solar PPA (with Rhudes Creek executed in the fourth quarter of 2019) and no wind PPAs. Thus, the Companies sought a third-party source for renewable PPAs and came across the LevelTen Energy PPA Price Index. LevelTen Energy collects PPA price information quarterly for RTOs across the nation. However, given the volatility of the quarterly data and to be consistent with the date the Rhudes Creek PPA was executed, the Companies averaged the prices in PJM and MISO since the fourth quarter of 2019 to develop a unique market price for wind and solar. The Companies also used the Rhudes Creek PPA price for solar technologies. Thus, the Companies were able to develop two avoided capacity costs for solar – one based on the Rhudes Creek PPA and the other based on the LevelTen Energy data.

2.1.1 Rhudes Creek Solar Project

The cost of energy for the Rhudes Creek solar project is $27.82/MWh over a 20-year term with no escalation. The Rhudes Creek project utilizes bifacial solar panels with single-axis tracking technology. This technology provides the most cost-effective means of procuring solar power for customers and is, therefore, used to compute avoided capacity costs for all solar technologies. In Table 2, the avoided capacity value for each solar technology is computed as the difference between the Rhudes Creek energy cost and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

[1] Table 2 in Supplemental Exhibit DSS-1 contains each technology's avoided energy cost.

Table 2: Rhudes Creek Solar Cost less Avoided Energy Costs ($/MWh)

Year	Rhudes Creek Solar	Avoided Energy Cost		Avoided Capacity Value: Rhudes Creek Solar less Avoided Energy Cost	
		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Solar: Single-Axis Tracking	Solar: Fixed Tilt
2022	27.82	23.04	23.33	4.78	4.49
2023	27.82	22.83	23.05	4.99	4.77
2024	27.82	23.12	23.38	4.70	4.44
2025	27.82	23.24	23.49	4.58	4.33
2026	27.82	22.64	22.82	5.18	5.00
2027	27.82	23.03	23.24	4.79	4.58
2028	27.82	22.81	22.95	5.01	4.87
2029	27.82	23.24	23.40	4.58	4.42
2030	27.82	23.82	23.94	4.00	3.88
2031	27.82	24.34	24.48	3.48	3.34
2032	27.82	24.89	25.05	2.93	2.77
2033	27.82	25.49	25.65	2.33	2.17
2034	27.82	25.25	25.49	2.57	2.33
2035	27.82	25.76	26.05	2.06	1.77
2036	27.82	26.24	26.47	1.58	1.35
2037	27.82	26.01	26.29	1.81	1.53
2038	27.82	26.07	26.47	1.75	1.35
2039	27.82	24.03	24.39	3.79	3.43
2040	27.82	23.65	24.05	4.17	3.77
2041	27.82	23.45	23.75	4.37	4.07
2042	27.82	23.76	24.06	4.06	3.76
2043	27.82	24.38	24.67	3.44	3.15
2044	27.82	24.81	25.13	3.01	2.69
2045	27.82	25.65	26.05	2.17	1.77

2.1.2 LevelTen Energy PPA Price Index

Each quarter, the LevelTen Energy PPA Price Index reports the prices that wind and solar project developers have offered for PPAs in various RTOs across the nation. Table 3 contains solar and wind PPA prices from the LevelTen report from Q4-2019 through Q1-2021.[2] The average of solar PPA prices

[2] LevelTen's quarterly reports are available at the following links:
Q4-2019: https://www.leveltenenergy.com/post/q4-2019
Q1-2020: https://www.leveltenenergy.com/post/q1-2020
Q2-2020: https://www.leveltenenergy.com/post/q2-2020
Q3-2020: https://www.leveltenenergy.com/post/q3-2020
Q4-2020: https://www.leveltenenergy.com/post/q4-2020
Q1-2021: https://www.leveltenenergy.com/post/q1-2021

in MISO and PJM over this period was $32.96/MWh. For wind, the average was $29.90/MWh. All PPA pricing is flat with no escalation over a 10-15 year term.

Table 3: LevelTen Energy PPA Price Index ($/MWh)[3]

	Solar				**Wind**		
	MISO	**PJM**	**Average**		**MISO**	**PJM**	**Average**
Q4-2019	28.50	32.70	30.60		24.90	26.00	25.45
Q1-2020	29.60	32.90	31.25		25.50	27.60	26.55
Q2-2020	29.00	33.00	31.00		23.30	33.50	28.40
Q3-2020	31.20	36.80	34.00		30.00	35.60	32.80
Q4-2020	33.70	37.50	35.60		33.00	35.50	34.25
Q1-2021	34.60	36.00	35.30		28.40	35.50	31.95
Average	**31.10**	**34.82**	**32.96**		**27.52**	**32.28**	**29.90**

In Table 4, the avoided capacity value for each solar technology is computed as the difference between the average LevelTen solar PPA price and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

[3] LevelTen provided 10th percentile PPA pricing for each RTO for Q4-2019 through Q2-2020 and 25th percentile pricing for each RTO for Q3-2020 through Q1-2021.

Table 4: LevelTen Solar PPA Index less Avoided Energy Costs ($/MWh)

Year	LevelTen Solar PPA Index[4]	Avoided Energy Cost		Avoided Capacity Value: LevelTen Solar PPA Index less Avoided Energy Cost	
		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Solar: Single-Axis Tracking	Solar: Fixed Tilt
2022	32.96	23.04	23.33	9.92	9.63
2023	32.96	22.83	23.05	10.13	9.91
2024	32.96	23.12	23.38	9.84	9.58
2025	32.96	23.24	23.49	9.72	9.47
2026	32.96	22.64	22.82	10.32	10.14
2027	32.96	23.03	23.24	9.93	9.72
2028	32.96	22.81	22.95	10.15	10.01
2029	32.96	23.24	23.40	9.72	9.56
2030	32.96	23.82	23.94	9.14	9.02
2031	32.96	24.34	24.48	8.62	8.48
2032	32.96	24.89	25.05	8.07	7.91
2033	32.96	25.49	25.65	7.47	7.31
2034	32.96	25.25	25.49	7.71	7.47
2035	32.96	25.76	26.05	7.20	6.91
2036	32.96	26.24	26.47	6.72	6.49
2037	32.96	26.01	26.29	6.95	6.67
2038	32.96	26.07	26.47	6.89	6.49
2039	32.96	24.03	24.39	8.93	8.57
2040	32.96	23.65	24.05	9.31	8.91
2041	32.96	23.45	23.75	9.51	9.21
2042	32.96	23.76	24.06	9.20	8.90
2043	32.96	24.38	24.67	8.58	8.29
2044	32.96	24.81	25.13	8.15	7.83
2045	32.96	25.65	26.05	7.31	6.91

In Table 5, the avoided capacity value for the wind technology is computed as the difference between the average LevelTen wind PPA price and the avoided cost of energy in Table 2 of Supplemental Exhibit DSS-1.

[4] $32.96/MWh is the average of solar PPA prices in MISO and PJM from Q4-2019 through Q1-2021.

Table 5: LevelTen Wind PPA Index less Avoided Energy Costs ($/MWh)

Year	LevelTen Wind PPA Index[5]	Avoided Energy Cost: Wind	Avoided Capacity Value: LevelTen Wind PPA Index less Avoided Energy Cost
2022	29.90	22.55	7.35
2023	29.90	22.47	7.43
2024	29.90	22.81	7.09
2025	29.90	23.10	6.80
2026	29.90	22.34	7.56
2027	29.90	22.80	7.10
2028	29.90	22.70	7.20
2029	29.90	23.09	6.81
2030	29.90	23.72	6.18
2031	29.90	24.33	5.57
2032	29.90	24.80	5.10
2033	29.90	25.46	4.44
2034	29.90	25.26	4.64
2035	29.90	25.69	4.21
2036	29.90	26.15	3.75
2037	29.90	25.95	3.95
2038	29.90	25.87	4.03
2039	29.90	25.19	4.71
2040	29.90	23.68	6.22
2041	29.90	23.76	6.14
2042	29.90	24.15	5.75
2043	29.90	24.49	5.41
2044	29.90	25.19	4.71
2045	29.90	25.56	4.34

2.2 Levelized Cost of a CT

CT units are available around-the-clock and designed for fast starts and load following. As a result, CT capacity is oftentimes viewed as the purest form of capacity. Table 6 summarizes the capital and fixed operating costs for a new CT. Overnight capital and fixed operating and maintenance ("O&M") costs are taken from the National Renewable Energy Laboratory's 2020 Annual Technology Baseline.[6] Firm gas transportation costs are based on the Companies' cost of firm gas transportation for the Trimble County CTs.

[5] $29.90/MWh is the average of wind PPA prices in MISO and PJM from Q4-2019 through Q1-2021.
[6] Source: https://data.nrel.gov/submissions/145.

Table 6: CT Capital and Fixed Operating Costs

Cost	2028 Installation (Real 2018 $)	2028 Installation (Nominal $)	Escalation
Overnight Capital ($/kW)	869	1,059	1.66%
Fixed O&M ($/kW-Year)	11.39	13.89	2.0%
Firm Gas Transportation ($/kW-Year)	N/A	25.47	2.0%

Table 7 contains the economic carrying charge for a CT, based on the cost and escalation assumptions in Table 6. 100% of these costs could be avoided if generation technologies with similar performance characteristics were added to the generation portfolio. However, solar and wind technologies are not available during the peak hour in all months. Therefore, only a portion of CT costs should be included when avoided costs are computed as a function of CT costs. Table 8 summarizes the availability of the QF resources during the peak hour for each month. The peak hour for each month is the hour in which the Companies' monthly peak most commonly occurred over the past 20 years. Note that "other technologies" are assumed to be 100 percent available to meet monthly peak load.

Table 7: CT Economic Carrying Charge ($/MW-Year)

Year	CT Economic Carrying Charge
2022	106,487
2023	108,372
2024	110,291
2025	112,244
2026	114,231
2027	116,255
2028	118,314
2029	120,410
2030	122,544
2031	124,715
2032	126,926
2033	129,176
2034	131,466
2035	133,797
2036	136,170
2037	138,585
2038	141,043
2039	143,546
2040	146,093
2041	148,686
2042	151,325
2043	154,011
2044	156,746
2045	159,529

Table 8: Availability of QF Resources during Peak Hours (% of Nameplate Capacity)

	Monthly Peak Hour Beginning (EST)		Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
Jan	7		0.0%	0.0%	35.7%	100.0%
Feb	7		0.0%	0.0%	36.3%	100.0%
Mar	7		3.6%	0.2%	33.8%	100.0%
Apr	6		0.9%	0.0%	18.4%	100.0%
May	15		72.5%	57.7%	39.0%	100.0%
Jun	15		79.9%	65.4%	25.6%	100.0%
Jul	14		81.4%	74.1%	23.4%	100.0%
Aug	15		74.4%	59.3%	23.5%	100.0%
Sep	15		71.7%	51.4%	27.8%	100.0%
Oct	15		62.2%	37.5%	44.8%	100.0%
Nov	7		0.1%	0.0%	11.8%	100.0%
Dec	7		0.0%	0.0%	23.6%	100.0%
Annual Average			**37.2%**	**28.8%**	**28.7%**	**100.0%**
Summer Average (Jun-Aug)			**78.6%**	**66.3%**	**24.2%**	**100.0%**

In Table 9, annual avoided costs are computed for each generation technology by multiplying the CT costs in Table 7 by the average annual availability factors in Table 8 (i.e., 37.2% for single-axis tracking solar, 28.8% for fixed tilt solar, and so on).

Table 9: Annual Avoided Capacity Costs Based on CT Cost ($/MW-Year)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	39,633	30,669	30,516	106,487
2023	40,335	31,212	31,056	108,372
2024	41,049	31,764	31,606	110,291
2025	41,776	32,327	32,166	112,244
2026	42,516	32,899	32,735	114,231
2027	43,269	33,482	33,315	116,255
2028	44,035	34,075	33,905	118,314
2029	44,815	34,679	34,506	120,410
2030	45,609	35,293	35,117	122,544
2031	46,418	35,919	35,740	124,715
2032	47,240	36,555	36,373	126,926
2033	48,078	37,203	37,018	129,176
2034	48,930	37,863	37,674	131,466
2035	49,798	38,534	38,342	133,797
2036	50,681	39,218	39,022	136,170
2037	51,580	39,913	39,714	138,585
2038	52,495	40,621	40,419	141,043
2039	53,426	41,342	41,136	143,546
2040	54,374	42,076	41,866	146,093
2041	55,339	42,823	42,609	148,686
2042	56,322	43,583	43,365	151,325
2043	57,321	44,356	44,135	154,011
2044	58,339	45,144	44,919	156,746
2045	59,375	45,946	45,717	159,529

To compute avoided capacity costs on a $/MWh basis, the annual values in Table 9 were divided by each technology's expected generation (see Table 10). The assumed capacity factors for each technology are listed in Table 1 of Supplemental Exhibit DSS-1. To compute a $/MWh value for "other technologies", the annual capacity payment was divided by 8,760 hours. The avoided capacity cost for single-axis tracking solar, for example, is higher than fixed tilt solar on an annual basis but lower on a $/MWh basis. Single-axis tracking solar has a higher average annual availability during peak hours (37.2% versus 28.8%), but its higher annual avoided capacity cost is divided over significantly more MWh.

Table 10: Avoided Capacity Costs Based on CT Cost ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	17.43	20.99	13.75	12.16
2023	17.74	21.36	13.99	12.37
2024	18.05	21.74	14.24	12.59
2025	18.37	22.13	14.49	12.81
2026	18.70	22.52	14.75	13.04
2027	19.03	22.92	15.01	13.27
2028	19.37	23.32	15.27	13.51
2029	19.71	23.74	15.54	13.75
2030	20.06	24.16	15.82	13.99
2031	20.42	24.58	16.10	14.24
2032	20.78	25.02	16.39	14.49
2033	21.15	25.46	16.68	14.75
2034	21.52	25.92	16.97	15.01
2035	21.90	26.37	17.27	15.27
2036	22.29	26.84	17.58	15.54
2037	22.69	27.32	17.89	15.82
2038	23.09	27.80	18.21	16.10
2039	23.50	28.30	18.53	16.39
2040	23.91	28.80	18.86	16.68
2041	24.34	29.31	19.19	16.97
2042	24.77	29.83	19.54	17.27
2043	25.21	30.36	19.88	17.58
2044	25.66	30.90	20.24	17.89
2045	26.11	31.45	20.59	18.21

2.3 Recommended Avoided Capacity Costs

Consistent with least-cost principles, the recommended avoided capacity costs for each technology are contained in Table 11. Because the LevelTen Energy avoided capacity values for solar are higher than the Rhudes Creek avoided capacity values, the Companies recommend using the Rhudes Creek values for the solar technologies. In the absence of Company-specific wind PPA data, the Companies recommend using the LevelTen Energy avoided capacity values for wind because they are lower cost than the capacity values computed based on the cost of a CT. Finally, the recommended avoided cost values for other technologies are computed based on the avoided cost of a CT. The Companies do not have PPA or index prices for the other technologies.

Table 11: Recommended Avoided Capacity Costs ($/MWh)

Year	Solar: Single-Axis Tracking	Solar: Fixed Tilt	Wind	Other Technologies
2022	4.78	4.49	7.35	12.16
2023	4.99	4.77	7.43	12.37
2024	4.70	4.44	7.09	12.59
2025	4.58	4.33	6.80	12.81
2026	5.18	5.00	7.56	13.04
2027	4.79	4.58	7.10	13.27
2028	5.01	4.87	7.20	13.51
2029	4.58	4.42	6.81	13.75
2030	4.00	3.88	6.18	13.99
2031	3.48	3.34	5.57	14.24
2032	2.93	2.77	5.10	14.49
2033	2.33	2.17	4.44	14.75
2034	2.57	2.33	4.64	15.01
2035	2.06	1.77	4.21	15.27
2036	1.58	1.35	3.75	15.54
2037	1.81	1.53	3.95	15.82
2038	1.75	1.35	4.03	16.10
2039	3.79	3.43	4.71	16.39
2040	4.17	3.77	6.22	16.68
2041	4.37	4.07	6.14	16.97
2042	4.06	3.76	5.75	17.27
2043	3.44	3.15	5.41	17.58
2044	3.01	2.69	4.71	17.89
2045	2.17	1.77	4.34	18.21

3 Calculation of Avoided Capacity Prices

As noted previously, the avoided capacity price for a given technology is computed as a function of the Companies' future need for generation capacity and the cost of avoided capacity. A 20-year QF contract beginning 2024 would defer the need for capacity in 2028 by 16 years to 2044. Similarly, the same contract would defer a 2034 capacity need by only 10 years. The sooner the capacity need, the higher the avoided capacity value. Table 12 lists the avoided capacity costs for each technology associated with a 20-year contract beginning in 2024. The first section in Table 12 contains avoided capacity costs associated with a 2028 capacity need; the second section contains avoided capacity costs associated with a 2034 capacity need.

Table 12: Avoided Capacity Costs for 20-Year Contract Beginning 2024 ($/MWh)

	Avoided Capacity Costs for 2028 Capacity Need				Avoided Capacity Costs for 2034 Capacity Need			
Year	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other
2024	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-
2028	5.01	4.87	7.20	13.51	-	-	-	-
2029	4.58	4.42	6.81	13.75	-	-	-	-
2030	4.00	3.88	6.18	13.99	-	-	-	-
2031	3.48	3.34	5.57	14.24	-	-	-	-
2032	2.93	2.77	5.10	14.49	-	-	-	-
2033	2.33	2.17	4.44	14.75	-	-	-	-
2034	2.57	2.33	4.64	15.01	2.57	2.33	4.64	15.01
2035	2.06	1.77	4.21	15.27	2.06	1.77	4.21	15.27
2036	1.58	1.35	3.75	15.54	1.58	1.35	3.75	15.54
2037	1.81	1.53	3.95	15.82	1.81	1.53	3.95	15.82
2038	1.75	1.35	4.03	16.10	1.75	1.35	4.03	16.10
2039	3.79	3.43	4.71	16.39	3.79	3.43	4.71	16.39
2040	4.17	3.77	6.22	16.68	4.17	3.77	6.22	16.68
2041	4.37	4.07	6.14	16.97	4.37	4.07	6.14	16.97
2042	4.06	3.76	5.75	17.27	4.06	3.76	5.75	17.27
2043	3.44	3.15	5.41	17.58	3.44	3.15	5.41	17.58

To compute the avoided cost price for a 20-year contract beginning in 2024, the Companies levelized the values in Table 12 over the period 2024 to 2043. Table 13 contains the results of this calculation.

Table 13: Levelized Avoided Capacity Price for 20-Year Contract beginning in 2024 ($/MWh)

	Avoided Capacity Costs for 2028 Capacity Need				Avoided Capacity Costs for 2034 Capacity Need			
Year	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other	Solar: Single-Axis	Solar: Fixed Tilt	Wind	Other
2024-2043	2.27	2.12	3.68	10.33	0.96	0.86	1.63	5.51

This calculation was completed for each technology and each year a 20-year contract can begin (2022 through 2026). The final results are summarized in Table 14.

Table 14: Recommended Avoided Capacity Prices ($/MWh)

Avoided Capacity Price for 2028 Capacity Need						
	2-Year	20-Year Level Price for Contracts Beginning:				
Technology	PPA (2021-2023)	2022	2023	2024	2025	2026
Solar: Single-Axis Tracking	0.00	1.82	2.05	2.27	2.50	2.73
Solar: Fixed Tilt	0.00	1.70	1.91	2.12	2.33	2.53
Wind	0.00	2.98	3.32	3.68	4.05	4.43
Other Technologies	0.00	8.27	9.27	10.33	11.48	12.71
Avoided Capacity Price for 2034 Capacity Need						
	2-Year	**20-Year Level Price for Contracts Beginning:**				
Technology	**PPA (2021-2023)**	**2022**	**2023**	**2024**	**2025**	**2026**
Solar: Single-Axis Tracking	0.00	0.67	0.82	0.96	1.10	1.23
Solar: Fixed Tilt	0.00	0.60	0.73	0.86	0.99	1.10
Wind	0.00	1.18	1.40	1.63	1.86	2.09
Other Technologies	0.00	4.05	4.75	5.51	6.34	7.22

The Companies' summer peak demand typically occurs in June, July, or August. Because solar and wind resources are not fully available during the peak hour in these months, the maximum amount of nameplate capacity eligible for an avoided capacity payment is computed by dividing the average capacity need in Table 1 by the QF resource's average summer availability in Table 8. For example, if 400 MW of single-axis tracking solar was added to the Companies' system in 2023, only the first 127 MW added would be eligible for an avoided capacity payment associated with deferring the summer capacity need in 2028.[7] The balance of the 400 MW would be eligible for an avoided capacity payment associated with deferring the summer capacity need in 2034.

[7] 127 MW is computed by dividing the average 2028 summer capacity need (100 MW in Table 1) by the summer average availability for single-axis tracking solar (78.6% in Table 2).

4 Appendix A

Table 15: Reserve Margin Need Assuming MC2, BR3 Retirements in 2028 (Scenario 1)

	2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**
Peak Load	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	6,009	6,010	6,013	6,014	6,014	6,014	6,010	6,011	6,009	6,010
Resources	7,686	7,686	7,686	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DLC	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43	42	41	40	39	39	38	37	37	36
MC NO_x Reduction	(297)	(297)	(297)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PPA	-	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-
Resources Before Ret.	7,577	7,655	7,653	7,949	7,948	7,946	7,945	7,943	7,942	7,941	7,940	7,939	7,938	7,937	7,936	7,935	7,934	7,933	7,932	7,932	7,931	7,851	7,851	7,850
Retirements																								
Small CTs [8]	-	-	-	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
MC1	-	-	-	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
MC2	-	-	-	-	-	-	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
BR3	-	-	-	-	-	-	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
GH1-2	-	-	-	-	-	-	-	-	-	-	-	-	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)
BR9	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
BR8, 10	-	-	-	-	-	-	-	-	-	-	-	-	-	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)
BR11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
GH3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)
MC3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(868)	(868)	(868)	(868)	(868)	(868)	(868)
BR6-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(292)	(292)	(292)	(292)	(292)	(292)	(292)
OVEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(152)	(152)	(152)	(152)	(152)	(152)
BR5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(130)	(130)	(130)	(130)	(130)
PR13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)
Dix 1-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	(32)	(32)	(32)	(32)
TC5-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)	(477)	(477)
TC8-10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)
TC1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(370)
Ohio Falls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(64)
Total Ret.	-	-	-	(347)	(347)	(347)	(1,056)	(1,056)	(1,056)	(1,056)	(1,056)	(1,056)	(2,137)	(2,379)	(2,500)	(3,459)	(3,459)	(4,619)	(4,771)	(5,080)	(5,557)	(5,557)	(6,034)	(6,468)
Resources Net of Ret.	7,577	7,655	7,653	7,602	7,601	7,599	6,889	6,887	6,886	6,885	6,884	6,883	5,801	5,558	5,436	4,476	4,475	3,314	3,161	2,852	2,374	2,294	1,817	1,382
17% Reserve Margin Need	**-**	**-**	**-**	**-**	**-**	**-**	**199**	**188**	**173**	**160**	**152**	**154**	**1,230**	**1,473**	**1,595**	**2,556**	**2,561**	**3,723**	**3,876**	**4,184**	**4,658**	**4,739**	**5,214**	**5,650**

[8] Haefling 1-2 and Paddy's Run 12

Table 16: Reserve Margin Need Assuming MC2, BR3 Retire at End of Depreciable Life (Scenario 2)

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
Peak Load	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	6,009	6,010	6,013	6,014	6,014	6,014	6,010	6,011	6,009	6,010
Resources	7,686	7,686	7,686	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687	7,687
CSR	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
DLC	61	60	58	56	55	53	52	50	49	48	47	46	45	44	43	42	41	40	39	39	38	37	37	36
MC NO_x Reduction	(297)	(297)	(297)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Solar PPA	-	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	-	-	-
Resources Before Ret.	7,577	7,655	7,653	7,949	7,948	7,946	7,945	7,943	7,942	7,941	7,940	7,939	7,938	7,937	7,936	7,935	7,934	7,933	7,932	7,932	7,931	7,851	7,851	7,850
Retirements																								
Small CTs [9]	-	-	-	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)	(47)
MC1	-	-	-	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)	(300)
MC2	-	-	-	-	-	-	-	-	-	-	-	-	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)	(297)
BR3	-	-	-	-	-	-	-	-	-	-	-	-	-	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)	(412)
GH1-2	-	-	-	-	-	-	-	-	-	-	-	-	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)	(960)
BR9	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
BR8, 10	-	-	-	-	-	-	-	-	-	-	-	-	-	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)	(242)
BR11	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)	(121)
GH3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)	(959)
MC3-4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(868)	(868)	(868)	(868)	(868)	(868)	(868)
BR6-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(292)	(292)	(292)	(292)	(292)	(292)	(292)
OVEC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(152)	(152)	(152)	(152)	(152)	(152)
BR5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(130)	(130)	(130)	(130)	(130)
PR13	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)
Dix 1-3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	(32)	(32)	(32)	(32)
TC5-7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)	(477)	(477)
TC8-10	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(477)	(477)
TC1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(370)
Ohio Falls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(64)
Total Ret.	-	-	-	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(347)	(1,725)	(2,379)	(2,500)	(3,459)	(3,459)	(4,619)	(4,771)	(5,080)	(5,557)	(5,557)	(6,034)	(6,468)
Resources Net of Ret.	7,577	7,655	7,653	7,602	7,601	7,599	7,598	7,596	7,595	7,594	7,593	7,592	6,213	5,558	5,436	4,476	4,475	3,314	3,161	2,852	2,374	2,294	1,817	1,382
17% Reserve Margin Need	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**818**	**1,473**	**1,595**	**2,556**	**2,561**	**3,723**	**3,876**	**4,184**	**4,658**	**4,739**	**5,214**	**5,650**

[9] Haefling 1-2 and Paddy's Run 12

Excel Attachments for Question 14(b) are being provided in separate files in Excel format.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 15

Responding Witness: Charles R. Schram

Q-15. Reference the Companies' generating units.

a. Identify the extent to which each unit owned and/or operated by the Companies experienced an unforced unit outage, and durations for each outage, during (1) January 2, 2014 through January 10, 20214 and (2) the Companies' winter peak event in 2015.

A-15.

a. The Companies assume that the information requested pertains to "forced unit outage", not "unforced unit outage". Unforced outages are effectively scheduled outages that are typically planned for non-peak seasons. See the following links to documents in the Commission's Fuel Adjustment Clause cases that include the requested forced outage data in response to Question No. 7 in each of the documents.

(1) KU_Formatted_1st_DR_V1_due_8-27-14_Final_Filed.pdf (ky.gov)[6]
LGE_Formatted_1st_DR_V1_due_8-27-14_Final_Filed.pdf (ky.gov)[7]

(2) KU_Formatted_1st_DR_FINAL_-_FILED_due_8-28-15.pdf (ky.gov)[8]
LGE_Formatted_1st_DR_FINAL_-_FILED_due_8-28-15.pdf (ky.gov)[9]

---

[6] https://psc.ky.gov/pscecf/2014-00227/robert.conroy%40lge-ku.com/08272014010019/KU_Formatted_1st_DR_V1_due_8-27-14_Final_Filed.pdf
7 https://psc.ky.gov/pscecf/2014-00228/robert.conroy%40lge-ku.com/08272014010453/LGE_Formatted_1st_DR_V1_due_8-27-14_Final_Filed.pdf
8 https://psc.ky.gov/pscecf/2015-00234/robert.conroy%40lge-ku.com/08282015074313/KU_Formatted_1st_DR_FINAL_-_FILED_due_8-28-15.pdf
9 https://psc.ky.gov/pscecf/2015-00235/robert.conroy%40lge-ku.com/08282015074514/LGE_Formatted_1st_DR_FINAL_-_FILED_due_8-28-15.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 16

Responding Witness: Stuart A. Wilson

Q-16. Reference Volume I of the Companies' 2021 IRP, footnote 33 on page 5-29, PDF p. 38 of 118. Since the October 19, 2021 IRP filing, have the Companies updated any of their distributed generation forecasts scenarios relied upon in preparing the 2021 IRP and depicted in Figure 5-13 to reflect the new rates and monthly netting established by the Kentucky Public Service Commission's September 24, 2021 final Order in the Companies' recent rate case? If yes, please provide each updated forecast. If no, please explain why not.

A-16. Yes. See the responses to PSC 1-14 and PSC 1-16.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 17

Responding Witness: Stuart A. Wilson

Q-17. Reference Volume I of the Companies' 2021 IRP, footnote 44 on page 5-42, PDF p. 48 of 118. Provide an update of the IRP to reflect the lower capacity resulting from the 125 MW solar PPA discussed in the footnote.

A-17. The Companies have not performed this analysis. The 35 MW difference in this planned solar facility is immaterial for integrated resource planning. It would have no impact on the Companies' resource plan.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 18

Responding Witness: Christopher D. Balmer / David S. Sinclair

Q-18. Reference LG&E/KU's 2021 RTO Membership Analysis (hereinafter "RTO Study"), Cost and Benefit Analysis ("CBA").

a. Reference CBA, Figure 1, page 6, Figure 3, page 8 and surrounding text, sections 7-10, and Appendices B and C. Provide all assumptions, data, methodologies, and rationales relevant to calculating the Companies' cost and benefit projections of RTO membership at a sufficient level of detail for a third-party to reproduce the results in the document.

b. Reference CBA, Figure 1, page 6, Figure 3, page 8 and surrounding text, sections 7-10, and Appendices B and C. Did the Companies assume that wholesale trade volumes would be the same whether LG&E and KU are a full RTO member? (Reference Appendix C for energy market trades, but please provide information about any other unreported market activity as well.) If no, please identify the assumptions and state the rationale for adopting each assumption.

c. Reference CBA, Figure 1, page 6, Figure 3, page 8 and surrounding text, sections 7-10, and Appendices B and C. Provide the supporting detail for the assumed transmission costs associated with RTO membership versus maintaining status quo and include this response whether and how the Companies have accounted for avoided costs.

d. Reference CBA, Figure 1, page 6, Figure 3, page 8 and surrounding text, sections 7-10, and Appendices B and C. What assumptions concerning planning and cost allocations have the Companies made in light of impending regional transmission planning and cost allocation reforms. Specifically, FERC is anticipated to reform regional transmission planning and cost allocation for all FERC Order 1000 Planning Regions, which includes non-RTO regions. LG&E and KU are part of Southeastern Regional Transmission Planning (SERTP). Has LG&E and KU taken that into account in its status quo case?

e. Reference CBA, Figure 1, page 6, Figure 3, page 8 and surrounding text, sections 7-10, and Appendices B and C. What are (1) the current costs of transmission and generation buildout when planning on a more local scale as compared to (2) the costs of sharing transmission buildout and participating in a market? Please provide an estimate of which, (1) or (2), may be larger if you cannot answer this more precisely.

f. Reference RTO Study, Appendix B. Did the Companies include current and projected transmission buildout costs or expenses under the status quo in the analysis?

g. Reference RTO Study, Section 8.3. If the Companies lose current transmission revenue streams, what transmission revenue would the Companies receive from the RTO tariff?

h. For any transmission revenue for the Companies from an RTO tariff discussed in the RTO Study, Section 8.3, is the revenue included as a benefit in the analysis? If yes, identify how. If no, state why not.

i. Reference RTO Study, Appendix B. Have the Companies discussed the study's estimates of projected costs allocated to the Companies with MISO and/or PJM as a means to confirm the estimates reasonableness and accuracy? If yes, provide the information, analysis, and/or feedback provided to the Companies? If no, explain why the Companies have not engaged in discussions with MISO and/or PJM concerning estimates of projected costs allocated to the Companies.

j. Reference RTO Study, Appendix B. Please identify and explain the assumption for capacity replacement costs or avoided capacity costs for units as they retire.

k. Reference RTO Study, Appendix B. Do the Companies include avoided capacity costs resulting from RTO membership as a benefit? If yes, explain how and identify the benefit. If no, explain why not.

l. Reference RTO Study Appendix B. Identify the implementation costs when the Companies first integrated into MISO and state whether the costs were more or less than the amount assumed in the study (adjusted for inflation).

m. Identify the amount of demand response the Companies have on their systems or otherwise in their territory. Further, state whether and how the Companies have accounted for the benefits of these resources. If the Companies have not accounted for the benefits of these resources, explain why not.

n. Reference RTO Study, Appendices B and C. For the Companies' analyses, state the costs that are considered as sunk costs and state the costs that are considered variable costs.

A-18.

a. See the response to JI 1-3. The attachments in the folder "2021RTOAnalysis" provide all of the data and workpapers used in the analysis.

b. No, the Companies did not assume that wholesale trade volumes would be the same if the Companies joined an RTO. As explained in Section 8.2 of the RTO study, the Companies modeled RTO membership by "dispatching/selling generating units into the RTO energy market and purchasing native load energy from the RTO energy market." These volumes would be dramatically more than the relatively small amount of wholesale energy purchases and sales that the Companies make today.

c. For the Mid and High case the MISO transmission costs were estimated using the MISO posted indicative rate for Schedule 26A and applying to the Companies' annual energy forecast as shown below:

		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
MISO MVP Expansion															
MISO Projected MVP Cost ($/MWh)		1.77	1.75	1.73	1.71	1.69	1.67	1.66	1.64	1.62	1.60	1.58	1.57	1.55	1.53
Adjust MISO rate down by 7% to adjust for LKE load in the denominator	1.07	1.65	1.63	1.62	1.60	1.58	1.56	1.55	1.53	1.51	1.50	1.48	1.46	1.45	1.43
LKE Energy for Load		32,079,289	32,044,532	31,838,787	31,647,991	31,532,217	31,519,019	31,369,729	31,279,396	31,243,163	31,283,029	31,196,075	31,171,902	31,187,799	31,288,968
LKE Projected MVP Cost ($M)		**53.0**	**52.3**	**51.4**	**50.6**	**49.9**	**49.3**	**48.5**	**47.9**	**47.3**	**46.8**	**46.2**	**45.6**	**45.1**	**44.8**

For the Low case, the costs in the Mid case were increased by a compound annual growth rate of 14.8% for ten years to reflect potential 400% increase in MISO transmission expansion cost. The Companies did not assume any reduction in the Companies' status quo transmission expansion plan cost as participant in an RTO as it is unlikely the RTO-wide transmission projects would have much, if any, impact on meeting NERC Transmission Planning Reliability Standards in the Companies' footprint.

d. Due to the timing of the FERC transmission planning reforms announcement and the completion of the RTO Study, no considerations were given to the potential impact of such FERC policy changes in the standalone operations.

e. The Companies have not performed this analysis.

f. Yes.

g. The Companies would expect to receive an amount of transmission revenue from an RTO tariff if it were a member. Each RTO has a complex methodology for allocating transmission revenues received by the RTO for Point-to-Point transmission service sold by the RTOs.

h. No. Due to the difficulties in projecting drive-through and drive-out transmission service sold by the RTOs as well as the flows and ratios that would be used to derive such an RTO allocation, the Companies did not attempt to determine the projected value of this allocation. It would not be expected to be a significant driver in RTO participation. When the Companies were previously members of MISO, annual revenue from drive-through and out transmission service were around $1 million.

i. No. The projected cost components used by the Companies in the analysis are readily available through the websites of both MISO and PJM. The analysis is designed to be a high-level screening analysis to determine if further investigation is warranted, which the analysis indicates is not.

j. The Companies did not make an assumption for capacity replacement costs in the RTO analysis, as explained in the RTO Study in the Executive Summary on page 5 and in Appendix B, which notes that the capacity benefits and costs are undetermined after 2027 when the Companies forecast a need for new capacity in the 2021 IRP. Capacity implications would be included in any final decision to join an RTO when more certainty is available regarding the future of the RTOs' capacity markets. As discussed in Section 3.3 of the RTO Study, changing market rules, especially as necessitated by a transition to renewable energy sources, are inevitable. In a recent report, PJM discusses the need for an evolution of PJM markets to accommodate increased renewable integration.[10] See attached. Similarly, the National Regulatory Research Institute ("NRRI")[11] concluded in a case study of reliability concerns surrounding rapid integration of intermittent resources that improvements to existing reliability planning methods are needed.[12]

k. See the response to part (j).

---

[10] "Energy Transition in PJM: Frameworks for Analysis," PJM, December 15, 2021. *See* https://pjm.com/-/media/library/reports-notices/special-reports/2021/20211215-energy-transition-in-pjm-frameworks-for-analysis.ashx.

[11] The NRRI is the research arm of the National Association of Regulatory Utility Commissioners ("NARUC").

[12] "The Intersection of Decarbonization Policy Goals and Resource Adequacy Needs: A California Case Study," NRRI, March 2021. *See* https://pubs.naruc.org/pub/55D05995-155D-0A36-315C-A161357DA070.

l. The Companies decided to become founding transmission-owning members of MISO more than 25 years ago.[13] To the extent the Companies analyzed the costs and benefits of becoming MISO founding members, the persons who conducted the analysis are no longer with the Companies, and the Companies are unaware of the location or contents of such analyses.

   Also, as originally conceived, MISO's primary function was to ensure coordinated transmission planning and operation among its members. Since then, MISO's functions and costs have increased dramatically as it evolved from an independent transmission system operator into a regional transmission organization ("RTO") that operates regional day-ahead and real-time energy markets, as well as a capacity market. Because MISO has undergone tremendous change from the time of its initial conception and founding, comparing integration and implementation expectations and costs from more than 25 years ago would be of little use, if any.

   Moreover, in July 2003 the Commission—on its own motion—opened an investigation into the Companies' MISO membership. After nearly three years of proceedings, the Commission issued an order on May 31, 2006 concluding that exiting MISO was in the interests of the Companies' customers.[14] In its order approving the Companies' exit from MISO, the Commission stated, "[T]he Commission finds the LG&E and KU analysis to be based on assumptions and inputs that are more reasonable than those incorporated by MISO's analysis."[15] The Commission further stated, "[T]he LG&E and KU analysis is more credible and it provides a more reasonable indication of the likely outcome of exiting MISO and pursuing the TORC [Transmission Owner with Reliability Coordinator] option. Therefore, LG&E and KU, and their retail customers, should economically benefit by exiting MISO and pursuing the TORC option."[16]

m. This information is provided in the IRP. The seasonal capacities of the Companies' demand response programs are shown in Table 5-1, on page 5-6 of IRP Volume I. These programs are not assumed to be included in the RTO analysis as explained on page 29 of the RTO Study.

n. No sunk costs are shown in Appendices B and C. The energy and capacity market values vary based on the amount of energy and capacity clearing these markets.

---

[13] *See* Case No. 2003-00266, Order at 1-2 (Ky. PSC July 17, 2003) ("LG&E and KU spent a number of years working with other Midwest utilities to organize MISO and they became charter members over 5 years ago.").
[14] Case No. 2003-00266, Order (Ky. PSC May 31, 2006).
[15] *Id.* at 16.
[16] *Id.* at 17.

Energy Transition in PJM: Frameworks for Analysis

Dec. 15, 2021

For Public Use

This page is intentionally left blank.

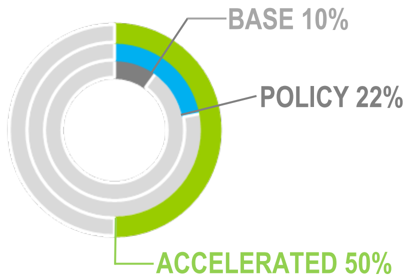
Contents

Executive Summary

Driven by PJM's strategic pillars – facilitating decarbonization, planning/operating the grid of the future, and fostering innovation – PJM has embarked on a multiphase, multiyear effort to study the potential impacts associated with the evolving resource mix. This "living study" will identify gaps and opportunities in the current market construct and offer insights into the future of market design, transmission planning and system operations.

The diverse set of PJM state policies were synthesized into three scenarios in which an increasing amount of the annual energy is served by renewable generation (10%, 22% and 50%). An entire year of the energy market was simulated with an hourly resolution.

The market rules of the energy market was simulated "as is" in 2020, and the capacity contributions of renewable resources were evaluated using the Effective Load Carrying Capability (ELCC) methodology. In the study, a qualitative assessment of NERC and power-industry-defined generator reliability attributes was also performed.



State policies were synthetized into three renewable scenarios. The *Base* is a counterfactual scenario with 10% of the annual energy in the PJM footprint coming from renewable generation. In the *Policy* and *Accelerated* scenarios, renewables represent 22% and 50% of the annual energy, respectively. In the *Accelerated* scenario, 70% of the generation dispatched is carbon-free.

This body of work is intended to be a living study, in which assumptions are continually refined based on internal and external stakeholder feedback. The initial findings should not be regarded as expected outcomes, but as bookends to be refined as the study progresses. The results of the study suggest five key focus areas for the PJM's stakeholder community and delineate the subsequent phases of the study.

1 | Correctly Calculating Capacity Contribution of Generators Is Essential

Resource Adequacy addresses whether there is sufficient generation available on the system to reliably meet customer demand. Historically, the hourly risk profile has been tightly coupled with periods of peak demand. The study showed that as the penetration of renewable resources increases, the risk profile shifts toward later hours in the evening, as peak net demand (load minus renewable generation) shifts toward the sunset. The ELCC methodology properly captured the capacity value of renewable resources, and there were no instances of load-shedding events in the energy market simulation.

In general, as the penetration of renewables increases, their capacity value contribution decreases under ELCC. As a result, an additional 78% nameplate capacity on top of the forecast peak load was required to satisfy the 1-in-10-year Loss of Load Expectation (LOLE) in the case with the greatest penetration of renewable resources. At those levels, there were periods of time in which more than a 130% of the instantaneous electricity demand was served by renewable resources. The 30% of surplus generation in excess of the electricity demand was exported to the Eastern Interconnection in the simulation.

FERC approved PJM's ELCC methodology in July 2021. Given the profound impact that the ELCC methodology had on the study results, it will be critical for PJM and stakeholders to continuously improve and incorporate sophisticated methods to accurately account for the capacity value contribution of all generation resources.

2 | Flexibility Becomes Increasingly Important With Growing Uncertainty

In power systems operations, there is always some level of uncertainty driven by deviations from what is forecasted. The study reaffirmed the need for operational flexibility to address the rise in uncertainty – findings include 50% steeper net-load ramping periods, frequent dispatch of generators to their economic minimum and lower capacity factors for thermal resources.

Intuitively, adding zero-marginal-cost renewable resources decreased the average locational marginal pricing (LMP) in all scenarios (by as much as 26%). Consequently, the overall size of the energy market in terms of revenues to resources and charges to load shrunk by a maximum of 40%. The study underscored the need for PJM and stakeholders to continue to work on price formation initiatives to ensure that the flexibility needs of the system are transparently priced in the market.

In general, transparent price signals that are aligned with real-time system conditions will best incentivize optimal operations and investments. However, forward procurements of ancillary service products could complement real-time price signals (just like the capacity market complements the energy market).

Procuring flexibility through market-based methods ensures that the true need for ancillary services is transparently priced and competitively procured in a cost-effective manner.

3 | Thermal Generators Provide Essential Reliability Services and an Adequate Supply Will Be Needed Until a Substitute Is Deployed at Scale

The essential reliability attributes of the generation mix were qualitatively assessed in the study. The comprehensive set of attributes evaluated include inertia, primary frequency response (PFR), reactive capability, ramping, regulation, fuel assurance and black start.

Given that the behavior of inverter-based resources is vastly different from that of traditional spinning-mass generators, the qualitative assessment revealed that, absent any reform, as the penetration of renewable resources increases, there is an overall decline in essential reliability services. The analysis also underscored the need for sophisticated analytical tools and studies to accurately assess grid stability.

Today, thermal resources supply essential reliability services. Until a different technology can provide a reliable substitute at scale, an adequate supply of thermal resources will be needed to maintain grid stability. PJM and stakeholders must ensure that the market structure provides the right incentives to maintain an adequate supply of these services.

In general, due to the massive size of the Eastern Interconnection (seven times the inertia of Texas), there is a long runway before wide-area impacts are expected to materialize. On the other hand, localized issues associated with system strength[1] ("weak grid") will have to be mitigated early into the fuel-mix transition.

4 | Regional Markets Facilitate a Reliable and Cost-Effective Energy Transition

The study underscored the benefits associated with the economies of scale within PJM Interconnection in facilitating the integration of renewable resources. Geographical diversity greatly attenuated the impact of the changing resource mix on the grid's essential reliability attributes. For example, the hourly ramping requirement was cut in half when comparing a geographically diversified versus a highly clustered renewable generation portfolio.

The analysis also showed the advantages of a robust interconnection between systems. PJM's exports increased by 140%, and its interchange with the Midcontinent Independent System Operator (MISO) peaked at more than 20 GW of power flow. At the time when the simulation results for this study were completed (2020), 20 GW of power flow from PJM to MISO represented more than double the maximum historical level. Interestingly, during the Texas winter event of 2021, PJM exported more than 14 GW to MISO, emphasizing once again the importance of the interconnection and overall generation portfolio diversity.

Intuitively, as the power flow in the network changed, so did the congestion patterns, and the simulations showed an overall increase in congestion hours. Renewable curtailments represented 10% of the total renewable generation production. Combined, these results suggest an opportunity for strategic regional transmission expansion, grid-enhancing technologies, and an increased need for storage.

The economies of scale, geographical diversity and robust transmission system of PJM Interconnection facilitate a reliable and cost-effective integration of renewable resources. The study results suggest an opportunity for strategic regional transmission expansion, grid-enhancing technologies, and storage.

5 | Reliability Standards Must Also Evolve

The qualitative analysis of essential reliability services highlighted an opportunity for enhanced coordination between the Federal Energy Regulatory Commission (FERC), the North American Electric Reliability Corporation (NERC) and states. Today, NERC's standards do not apply to resources connected at the distribution network. FERC Order 2222 provides an opportunity for distributed energy resources (DER) to participate in wholesale electricity markets and provide value to the grid, further blurring the conventional boundaries between the transmission and distribution systems. As the penetration of DER increases in the grid, it will be critical to hold DER to an appropriate level of performance, cybersecurity and reliability standards such as IEEE Standard 1547.

---

[1] "System strength" denotes the ability of the power system to maintain a healthy voltage waveform. During a disturbance, synchronous generators can provide a temporary burst of energy 10 times greater than its nominal rating. In a strong grid (with a highly dense mesh of transmission lines and synchronous generators), the voltage waveform recovers quickly after a disturbance, enhancing grid stability. In a "weak grid," the impact of a disturbance is exacerbated, leading to potential controller instability and cascading outages.

Similarly, interdependent infrastructure (gas, water, telecommunications, etc.) should also be held to appropriately stringent reliability requirements tailored to their particular industries. Extreme weather events (like the Texas winter event) provide a sobering reminder that reliability cannot be achieved in a vacuum. Interdependent infrastructure will play an ever-important role and should be on comparable footing regarding reliability requirements. These interdependencies were not evaluated as part of the initial renewable integration analysis, but they will become increasingly important as other sectors of the economy (e.g., transportation, heating) become more dependent on the electric power grid.

Reliability cannot be achieved in a vacuum. In order to facilitate a reliable energy transition, the evolution of PJM's markets, operations and transmission planning must be accompanied by the advancement of comparable reliability requirements across interdependent infrastructure.

Analysis Framework

Previous Analyses

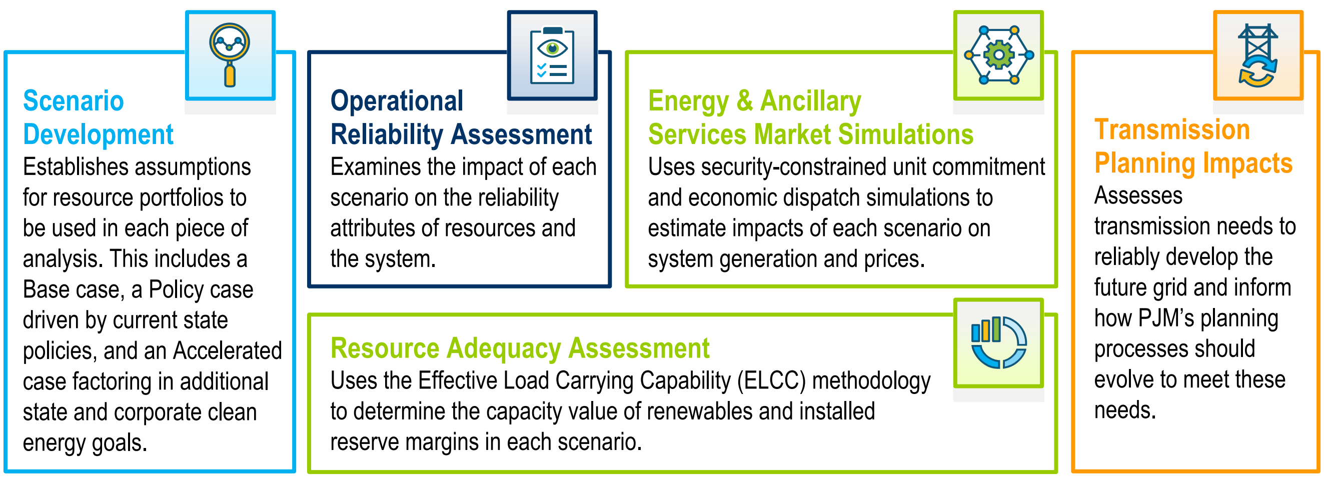
PJM's March 2021 white paper "Reliability in PJM: Today and Tomorrow" provides an overview of bulk power system reliability in terms of four basic building blocks that a grid operator must have in place today and plan to provide in the future: adequate supply, accurate forecasting, robust transmission and reliable operations. That paper was intended to help provide the proper context for discussions on system reliability with policymakers and stakeholders.

It also began a review of how PJM's core functions, market rules, operations and planning processes should evolve to maintain reliability in the face of the changes occurring in the electric industry. PJM has reviewed other renewable integration studies in order to inform its approach and methodology. Many of these studies include robust combinations of analyses that took place over multiple years.[2]

The 2014 "PJM Renewable Integration Study" conducted by GE Consulting, found that the PJM system, with adequate transmission expansion and additional regulation reserves, would not have any significant reliability issues operating with up to 30% of its energy provided by wind and solar generation. The 2017 "PJM's Evolving Resource Mix and System Reliability" report defined several attributes that are critical for system reliability and highlighted the change in reliability attribute needs to support the evolution of the PJM resource mix.

The following sections described in Figure 1 outline key elements of the analysis framework, as well as takeaways from initial phases of PJM's analysis.

Figure 1. Framework for Analyzing Energy Transition in PJM



[2] Other studies referenced include the NREL "Eastern Renewable Generation Integration Study," MISO "Renewable Integration Impact Assessment," Itron & Analysis Group "NYISO Climate Change Impact Study" and Brattle "New York's Evolution to a Zero Emission Power System."

Scenario Development

The first part of the analysis framework is to develop scenarios that will serve as reference points for studying the impacts of an evolving resource mix in PJM. PJM developed resource expansion and resource retirement assumptions by analyzing government and corporate policies driving clean-energy growth and generation retirements across PJM states, trends in the PJM interconnection queue and industry projections of the evolving system mix.[3] Onshore wind, offshore wind and solar resources are considered for expansion in three scenarios:

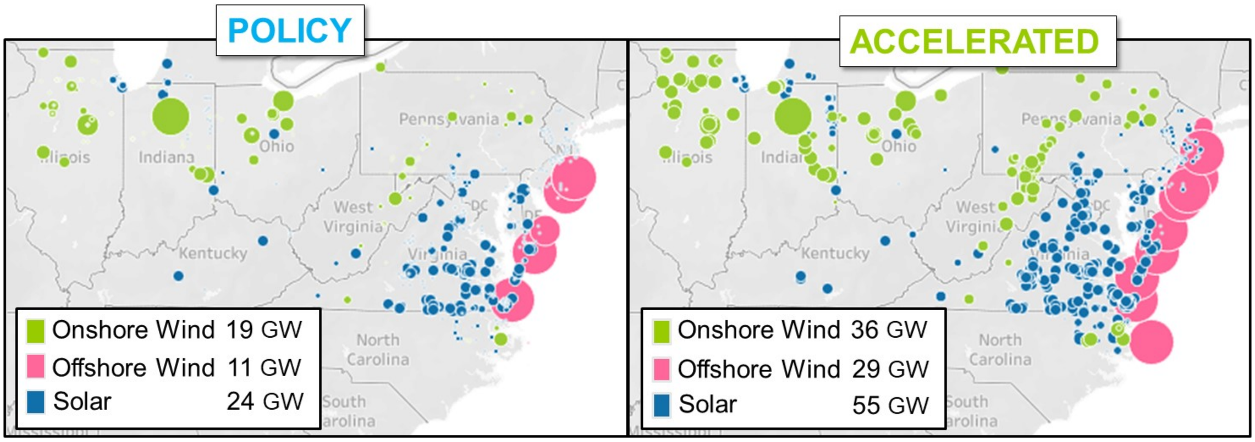
1 | **Base:** The amount of wind, solar, battery energy storage and solar-storage hybrid resources anticipated in the most current Regional Transmission Expansion Plan.

2 | **Policy**: References state and corporate clean-energy targets for 2035,[4] which combined would result in 22% of the energy in the PJM footprint coming from renewable generation, with the ability to provide up to 90% of PJM's instantaneous peak.

3 | **Accelerated:** References additional state and corporate clean-energy targets extending to 2050,[5] which combined would result in 50% of the energy in the PJM footprint coming from renewable generation, with the ability to provide 30% more energy than PJM's instantaneous peak.

The resource expansion is shown in Figure 2. Future phases of this analysis will also consider the expansion of battery energy storage and solar-storage hybrid resources.

Figure 2. Renewable Generation Expansion in Policy and Accelerated Scenarios



[3] Industry sources: IHS Markit North American Power Market Outlook and EIA Annual Energy Outlook.

[4] The State policies used to inform the scenarios were those in place as of April 2020. Future iterations of the study will continuously use updated versions of such policies.

[5] See footnote 12.

All portfolios included formal deactivation notices as well as state or utility policies or agreements that include the shutdown of fossil generation beyond units that have formally submitted deactivation notices to PJM. Additional fossil generation retirements were included in the Policy and Accelerated cases to offset the additional capacity added by the renewable buildout.

The study assumed that existing nuclear generation resources would complete the Subsequent License Renewal process to remain operational through the policy reference years. Future studies may consider additional retirement sensitivities. The gross load from the long-term load forecast for the year 2035 was used in all three scenarios. The net load varied in each scenario to account for the impact of behind-the-meter solar.[6] In future studies, sensitivities may also include the impacts of high electrification.

Resource Adequacy Assessment

A system with increased variable resources will require new approaches to adequately assess the reliability value of each resource and the system as a whole, which will impact the amount and characteristics of the resources needed to provide sufficient reserves. PJM used the ELCC methodology, recently approved by FERC,[7] to determine the capacity value of renewables and installed reserve margins under each study scenario.

The Capacity Value of Renewables: Effective Load Carrying Capability

The ELCC method was used to assess the resource reliability value (also referred to as capacity value) tied to the concepts of resource adequacy and probabilistic evaluation. Each portfolio under examination had the same gross load but varying amounts of solar (both behind-the-meter and in-front-of-the-meter), onshore wind and offshore wind. These varying penetration levels had an impact on net demand – or the amount that needs to be met after taking into account contributions from renewables – and ultimately on the reliability value of the variable resources.

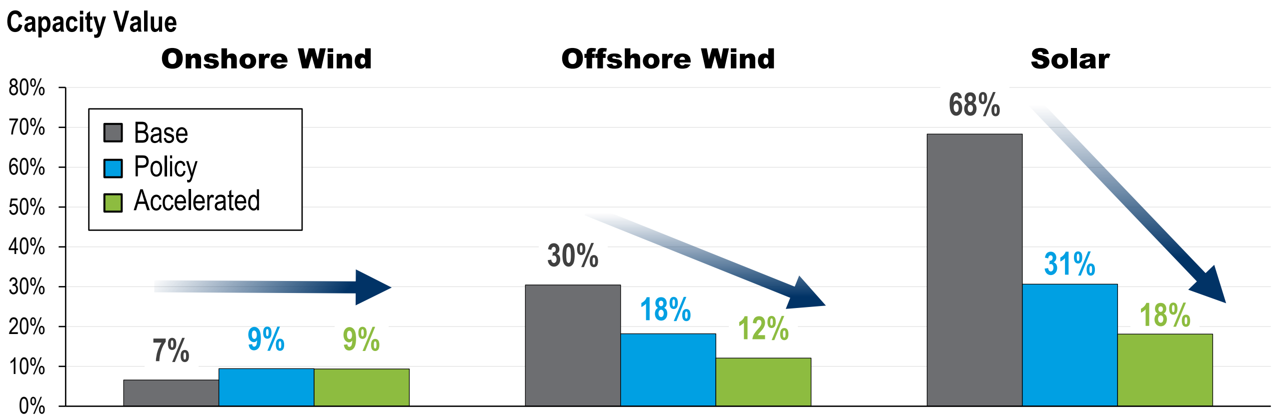
For traditional resources such as a thermal generator, ELCC is approximately equal to its unforced capacity (UCAP) value (which is determined based on the resource's forced outage rate). For variable resources, such as wind and solar, ELCC methodology is applied to derive a UCAP-equivalent value. ELCC results are driven by those hours with high risk or high loss-of-load probability (i.e., hours experiencing shortage or near-shortage conditions). These risk hours may vary as penetration of the variable resource increases.

[6] For the Base and Policy scenarios, the IHS Markit behind-the-meter (BTM) solar forecast was used to determine the renewable energy contribution from BTM solar resources. The Base scenario used the expected BTM solar penetration in 2023 from the IHS Markit solar forecast and scaled it up to 2035 load levels. The Policy scenario used the 2035 BTM solar forecast. In order to produce BTM solar values for the Accelerated scenario, guidance was taken from the Energy Information Administration on regional BTM solar growth between 2035 and 2050 to scale up the Policy scenario values.

[7] ELCC replaces the existing methodology of determining the capacity value of renewables, which only considers performance during certain peak hours in the summer. ELCC uses a more robust, probabilistic analysis that considers the contribution to reliability that resources provide during all hours of high risk, including net-peak-demand hours, and accounts for the limited duration of storage resources.

Study results indicate that as renewable penetration increased, risk shifted to hours in which the resources under study do not perform as well. This can be seen in the ELCC results. Figure 3 shows the results as variable resource penetration increases from the Base to Policy to Accelerated cases.

Figure 3. Effective Load Carrying Capability Results by Resource Type



ELCC results were sensitive to the input data, which included both the mix of profiles used and the assumption of resource performance. For instance, many solar resources entering the interconnection queue are hybrids (solar paired with storage), and these would have higher ELCC values depending on the storage capability and dispatch assumptions. Because of these and likely other factors, ELCC values presented should not be considered predictive for future ELCC values. Future analyses will refine the underlying assumptions and integrate energy storage and hybrid resources into the model.

Resource Adequacy Implications

PJM conducts an annual Reserve Requirement Study, which evaluates capacity needs on top of forecasted load in order to meet PJM's Loss of Load Expectation (LOLE) criterion of 0.1 days per year.

Because of the declining reliability value of renewable resources, the percent nameplate above peak load would increase under each progressive scenario. In the Accelerated scenario, an additional 78% nameplate capacity on top of the forecasted peak load was required to satisfy the 1-in-10 year LOLE. At those levels, there were periods of time in which more than 130%[8] of the instantaneous electricity demand was served by renewable resources.

[8] The 30% of surplus generation in excess of the electricity demand was exported to the Eastern Interconnection.

In PJM's capacity market, known as the Reliability Pricing Model, procurement needs are dictated through the Forecast Pool Requirement, which is the amount of UCAP needed to meet PJM's reliability criteria. Shifting to an ELCC-based concept for determining variable resources' UCAP value provides a better alignment between capacity offers and its ability to produce energy in the hours needed to serve load. PJM's practice prior to ELCC assigned capacity value according to a resource's performance from 2–6 p.m. from June 1 through Aug. 31. This measure ignores the changing hourly risk profile of renewable resources and became detached from reliability value as penetration increased in the analysis. For example, PJM's previous practice would provide solar with too much value relative to its reliability contribution in the Policy and Accelerated cases.

Energy & Ancillary Service Market Simulations

In order to analyze the impacts of increased renewable generation in the PJM wholesale electricity markets, PJM used a production cost model to simulate security constrained unit commitment and economic dispatch over a one-year period for each renewable penetration scenario.[9] The insights PJM intends to gain from comparing the results of these simulations with increasing renewable penetration levels and thermal generation retirements include:

- Impacts on reserve procurement and prices
- Impacts on locational marginal prices and system production cost
- Shifts in generator commitment, revenues, curtailments and interchange
- Ramping needs due to shifts in net demand
- Shifts in system emissions

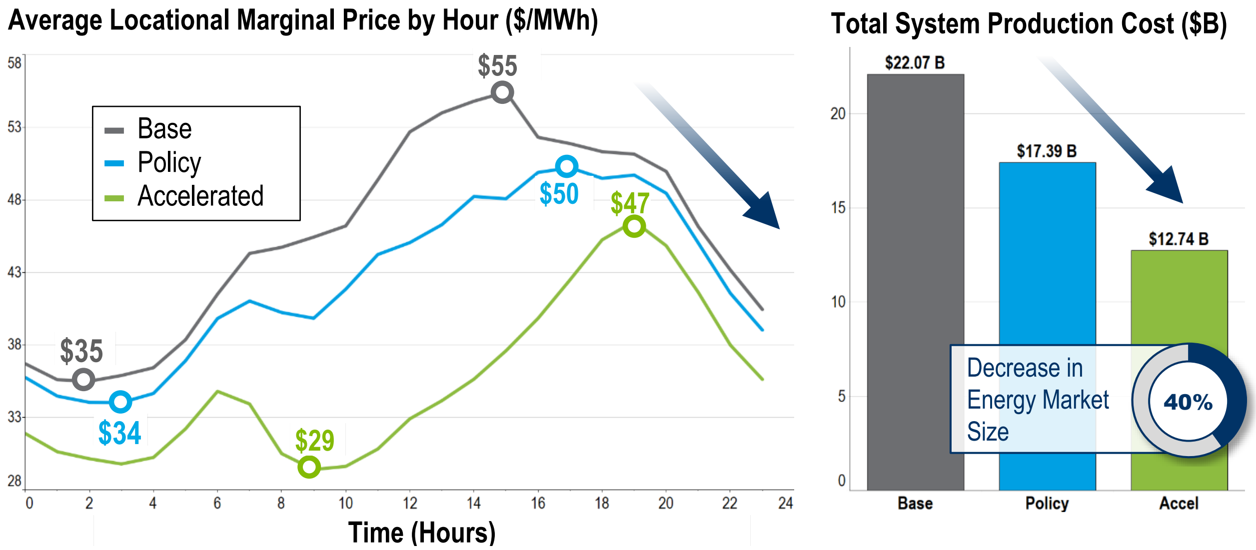
Locational Marginal Prices

Figure 4 shows the Energy Market dynamics. Across all hours, the average LMP decreases by 26% from the Base scenario to the Accelerated scenario with the highest penetration of renewables. The overall size of the energy market shrunk by 40%, as measured in terms of total system production cost. Reserves were modeled to be consistent with PJM's current business rules.[10] Future analysis will include Operating Reserve Demand Curve (ORDC) modeling consistent with enhanced reserve price formation business rules.

[9] PJM used Energy Exemplar's PLEXOS® Integrated Energy Model (PLEXOS), a production cost model that performs both a security-constrained unit commitment and dispatch over a given time horizon.

[10] Shortage pricing of reserves was modeled with a single $850/MW step. Thermal and hydroelectric resources were modeled to provide reserves where eligible, given ramping and startup participation constraints.

Figure 4. Energy Market Indicators



Generation Dispatch

Annual generation by fuel type for each scenario is shown in Figure 5. In the Accelerated scenario, 70% of the generator dispatched is carbon-free (renewables + nuclear). Total tons of carbon dioxide emissions were reduced by 40% when compared to the Base scenario.

The study revealed a substantial amount of renewable generation curtailments. As shown in Figure 6, such curtailments were particularly exacerbated during periods of time in which high renewable generation coincided with low periods of electricity demand.

Figure 5. Annual Energy Generation by Fuel Type (GWh)

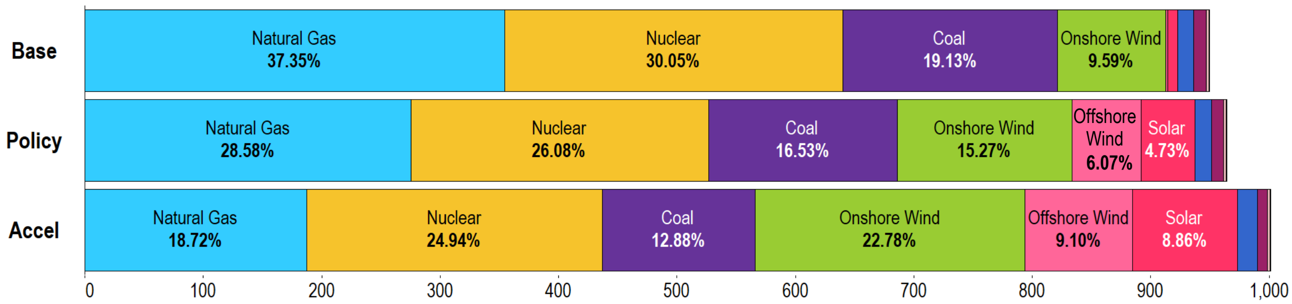
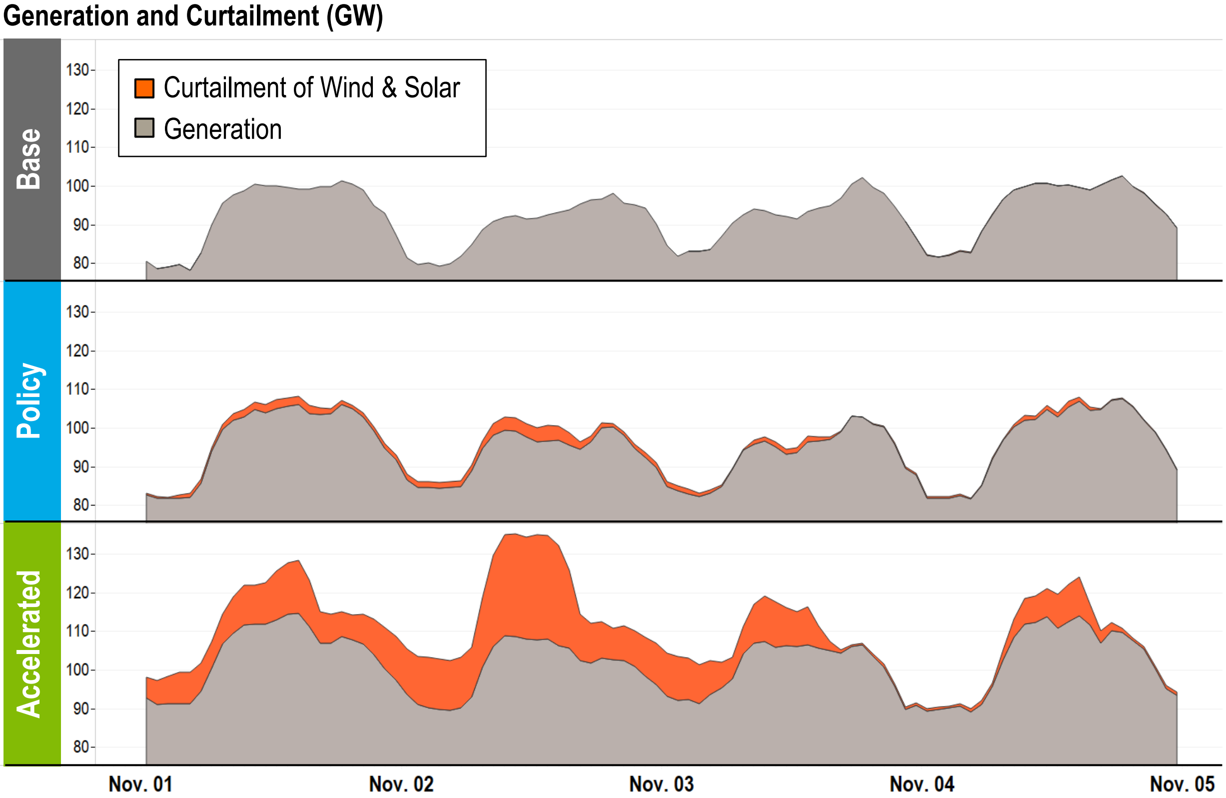


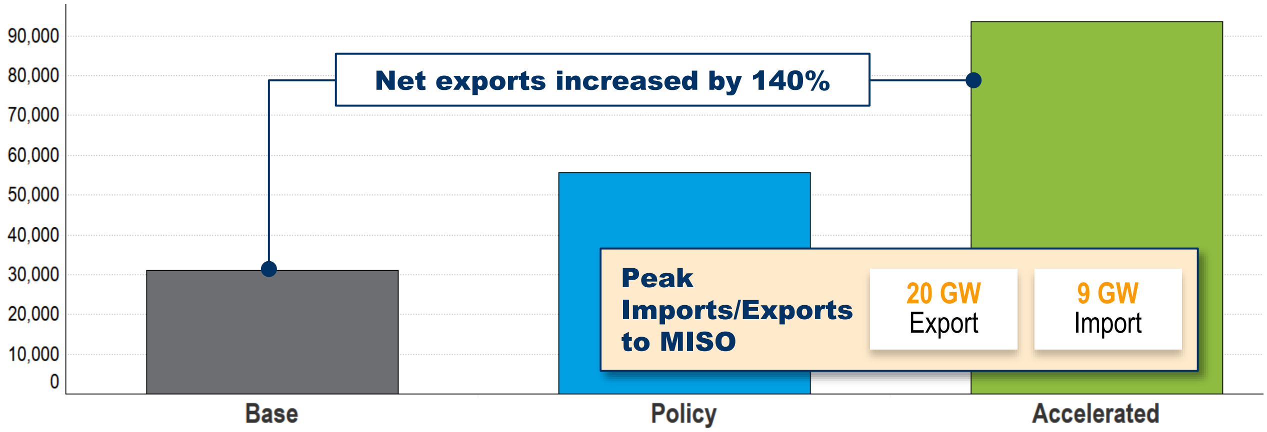
Figure 6. Renewable Generation Curtailments



Interchange and Congestion

Total net exports for the simulated year in each scenario are shown in Figure 7.

Figure 7. Total Annual Net Exports and Peak Export/Imports with MISO (MW)



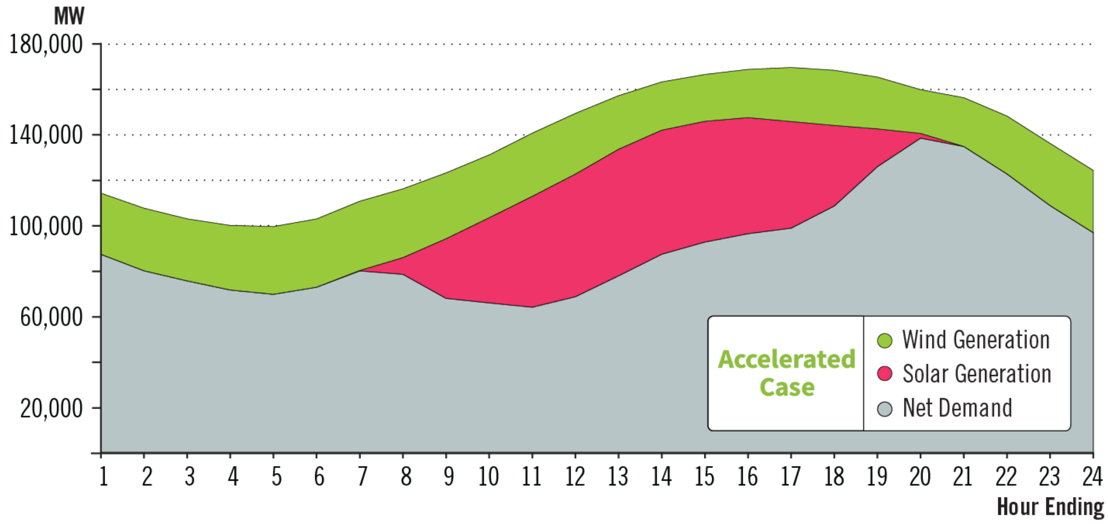
PJM exports increased by 140%, and interchange with MISO peaked at more than 20 GW of power flow. Congestion patterns across the PJM grid changed significantly. In the Accelerated scenario, the total hours of transmission line congestion increased by about 50%, and a significant amount of renewable curtailment was needed to manage transmission limitations and minimum generation events.

Together these initial results speak to the importance of efficient and nimble transmission planning as a tool for integrating renewables in a reliable manner and highlight the need for enhanced forecasting techniques for managing uncertainty (as detailed in the Operational Reliability section).

Flexibility To Address Uncertainty

Simulation results indicated an increased need for operational flexibility, with steeper ramps, frequent dispatch of generators to their economic minimum and lower capacity factors for natural gas and coal resources. Figure 8 shows the ramping requirements for the average summer load curve under the Accelerated scenario. The maximum load ramps were approximately 11 GW/hour in all scenarios. However, the net-load ramping (load minus renewable generation) varied drastically among scenarios. In the Base scenario, the net-load ramping was 12 GW/hour. In the Accelerated scenario, the net-load ramping requirement climbed up to 19 GW/hour.

Figure 8. Ramping Requirements for Summer Load Curve (Accelerated Scenario)



Operational Reliability Assessment

Reliability attributes are essential for maintaining system balance and supporting the reliable operation of the grid.[11] This section focuses on assessing the reliability impacts of proposed clean-energy programs and state initiatives. It is also intended to support the development of a PJM action plan to prepare for and manage the impacts of increasing levels of renewables on the regional high-voltage electric system.

PJM conducted extensive industry research and outreach, which was integral to inform the overall operations analysis. PJM also performed a qualitative assessment of NERC and power-industry-defined generator reliability attributes. This assessment was based on industry research, historical PJM system performance and the three future resource portfolios (Base, Policy and Accelerated) described previously in the Scenario Development section.

Key generator reliability attributes analyzed include the following:

- Inertial and Primary Frequency Response (PFR)
- Reactive Capability
- Ramping
- Regulation
- Flexibility
- Fuel Assurance
- Black Start
- System Stability

Reliability Attributes

Primary Frequency Response

Primary frequency response (PFR) is essential for grid reliability within the PJM footprint. It is the first line of defense to maintain frequency, it is critical for system restoration and it is necessary for accurate modeling and regulatory compliance. PFR is the inherent response of resources and load to detect and arrest local changes in frequency. It is an automatic, locally detected response by resources that is not driven by any centralized system and begins within seconds after a frequency excursion. It is essential to stopping a decline in frequency and preventing the activation of automatic under-frequency load shedding (UFLS). The fast, inherent response is a larger differentiator between PFR and regulation, the latter of which follows a centralized dispatch signal from PJM.

In February 2018, FERC Order 842 revised the regulations of provision for PFR by requiring new generating facilities to install, maintain and operate a functioning governor or equivalent controls as a precondition of interconnection (for both large and small generator interconnection agreements). These requirements were documented in PJM Interconnection Service Agreements as of Oct. 1, 2018.

---

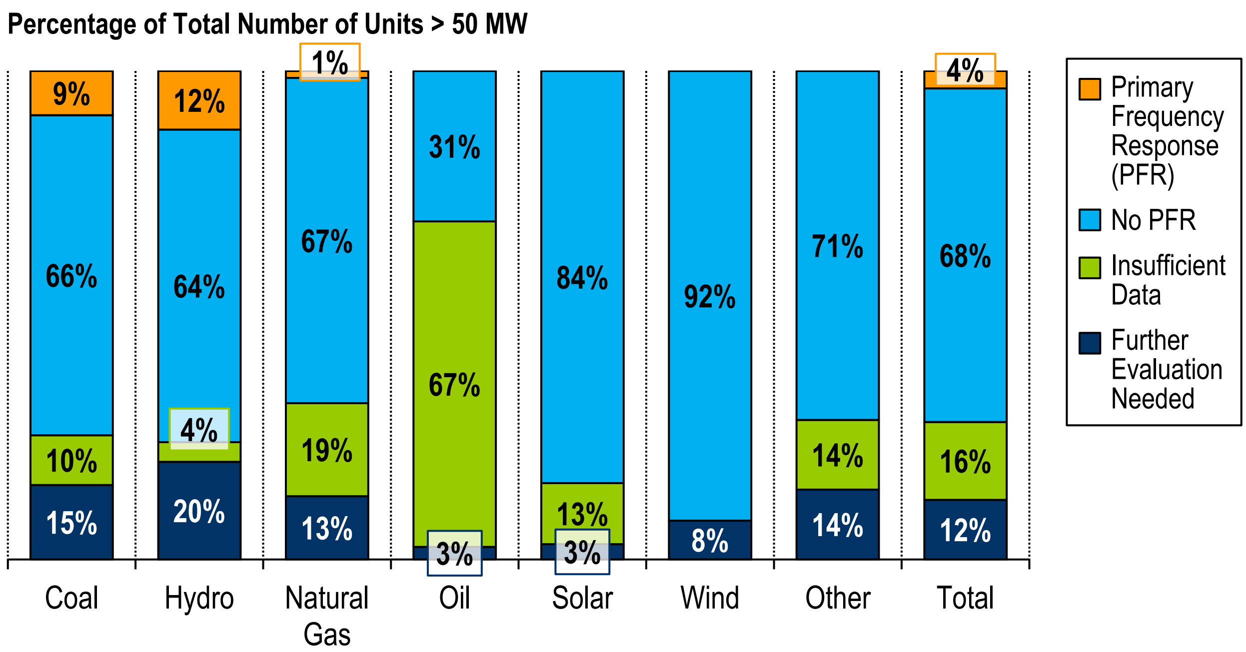
[11] These reliability attributes were previously analyzed and discussed in the 2017 white paper "PJM's Evolving Resource Mix and System Reliability" and in the March 2021 white paper "Reliability in PJM: Today and Tomorrow."

While FERC Order 842 requires PFR capability, it does not require resources to operate with headroom; therefore, PFR to under-frequency events is generally minimal for those resources operating at full output. Current event evaluations indicate renewable resources tend to operate at full output, and future renewable integration, along with a change of online resources, continues to be studied to best determine potential future needs for sufficient PFR.

PJM currently does not have requirements for either frequency-responsive generation or PFR reserves. Based on preliminary analysis, in the short term, PJM does not see a reliability concern with the amount of PFR on the system. However, PJM does see that PFR, maintaining adequate headroom, or PFR Reserve, are areas that will require ongoing monitoring and a possible reactivation of the Primary Frequency Response Senior Task Force.

In addition to the NERC BAL-003-2 Frequency Response and Frequency Bias Setting[12] Reliability Standard, PJM performs additional frequency response analysis, as documented in PJM Manual 12. This additional analysis is performed to evaluate generator PFR performance in the PJM footprint. Section 3.6 of PJM Manual 12: Balancing Operations (M-12) includes the criteria for evaluating the PFR performance of generating resources following an event and takes into account the droop, deadband and operating requirements in PJM Manual 14D: Generator Operational Requirements. This analysis evaluates units that are at least 50 MW and above and units that are FERC Order 842 compliant. Figure 9 shows the M-12 event evaluations shared at the June 10, 2021, Operating Committee meeting.

Figure 9. M-12 Primary Frequency Response Review as of June 10, 2021



12 NERC Standard BAL-003-2 Frequency Response and Frequency Bias Setting

The inertial frequency response of the system drops as large synchronous generators are retired and replaced with inverter-based resources such as wind, solar and storage. This can be a concern in a grid with high penetration of renewables, as it can result in a faster and larger frequency decline following a system disturbance because of a reduced level of reliance on generators with large rotating masses. In the future, consideration of how to secure inertial frequency response may become necessary to ensure an adequate supply on the system at all times and appropriately value those resources providing the service.

Reactive Capability

In 2016, FERC issued Order 827. This new order set reactive capability requirements for all nonsynchronous machines. Nonsynchronous generators now must have the capability of providing dynamic reactive power support and maintain a 0.95 power factor lagging and leading for the full range of active power output.

Since reactive power for inverter-based resources is controlled by power electronics, inverter-based resources can theoretically provide 1.0 pu apparent power at a power factor of zero lagging or leading, with 100% of inverter capability dedicated to providing or absorbing reactive power. This is very rare, though. Renewable facilities are not incentivized to operate at such a low power factor, and other design issues must be considered.

Instead, analysis reveals that inverter-based resources typically report “V-curves,” triangle-shaped reactive capability that is dependent upon, and proportional to, the real power output. These are not representative of the full theoretical reactive capability of inverter-based resources but instead appear artificially limited only to meet FERC Order 827 requirements. A review of PJM requirements for reporting, testing and providing reactive capability is suggested to ensure that PJM is sufficiently documenting and using the full reactive capability of the inverter-based resource fleet.

The DC link capacitor in inverters uses similar technology to that of a static synchronous compensator (STATCOM). With an additional initial investment, inverter-based resources can be designed to provide or consume reactive power at near-zero real power outputs. The additional design allows an inverter to consume a small amount of AC active power from the grid, instead of DC power from the plant, to power the link capacitor and associated power electronics in STATCOM mode. When this feature is built into the inverter, the capability is always there for future use at little operational cost.

However, this additional functionality comes with additional costs to the generation owner. On top of the higher initial investment and paying for increased active power consumption in standby mode, the generation owner also suffers additional costs related to increased maintenance and decreased power electronics lifespans.

The capability of inverter-based resources to regulate voltage without active power output could be useful in many scenarios, including solar farm reactive support after sunset, solar farms helping stabilize voltage during winter morning peak, voltage support from solar and wind farms at night during lighter loads and wind farm voltages support in remote areas during no-wind conditions. Enabling reactive capability in inverter-based resources would also potentially limit or avoid the need to install additional transmission devices for voltage control, such as SVCs, capacitors and reactors.

Ramping

Ramping is upward or downward control by resources over a period of time needed to maintain load-generation balance. This is most needed at times of major load shifts, especially during the winter evening ramps, when increases in load coincide with decreases in solar output, and are potentially amplified by wind output changes.

PJM performed a ramping capability analysis accounting for an increase in renewable resources. This analysis factored in maximum expected ramping capability and load forecasts. Requirements will remain unchanged for the near future because of a significant amount of ramping-capable generation on the system. Further analysis is needed to make sure PJM can stay ahead of any ramping capability deficiencies and identify any areas where renewable resources will closely synchronize their ramping behaviors.

A large amount of hybrid generation pairing solar with energy storage is in PJM's interconnection queue. These resources could provide great ramping capability depending on the size of the storage component.

Regulation

Ramping, regulation and reserves can be seen as a generator's ability to follow load, and all three are structured by NERC BAL (Resource and Demand Balancing) standards.

Regulation is the fastest of the three, requiring generators to control Area Control Error (ACE) and frequency deviations in a matter of seconds to a few minutes. Ramping capability and reserves are the generator's ability to follow the load shape over a matter of several minutes to an hour, or even days for more forward-looking reserves.

PJM assessed its regulation capability with higher renewable penetrations by examining current participation in regulation in PJM and how other ISOs/RTOs are incorporating higher renewable penetrations.

Currently, solar and wind units do not participate in PJM's Regulation Market, but there is significant participation from energy storage resources (ESRs). Therefore, hybrids that consist of renewables paired with ESRs may be an option for renewable resources to participate in the Regulation Market. PJM and stakeholders are currently examining hybrid resources in the PJM DER & Inverter-Based Resources Subcommittee (DIRS).

Other RTOs/ISOs have already seen a larger amount of renewable integration. Significant amounts of wind generation are installed in the Southwest Power Pool (SPP), Electric Reliability Council of Texas (ERCOT) and MISO systems. California ISO (CAISO) has a large amount of both wind and solar generation installed. PJM will need to review different market structures in order to plan for the best way to use renewable resources for regulation purposes. Next steps include analyzing how renewables and hybrid resources can participate and perform as regulation resources.

Flexibility

Flexibility is a reliability attribute that measures the ability of a unit to turn on and off quickly and frequently in a single operating day. Three characteristics that commonly determine a resource's flexibility are cycling capability, quick-start time and low minimum run times.

Units with the ability to start or stop quickly allow operators to balance load and generation during periods when load and/or generation are changing quickly, or when there is significant uncertainty in the load forecast. Renewable energy resources can be dispatched down but cannot be guaranteed to return to previous output levels or be dispatched up. An evaluation of existing requirements, regulations and rules should be completed to ensure all resources are incented and capable of providing flexibility.

PJM will review different market approaches to best incentivize renewable energy resources to be their most flexible. As renewable resource penetration increases, upward flexibility continues to decline, and downward flexibility continues to improve. A future analysis should observe the flexibility of each hour of dispatch in both the current system and future cases. The objective would be to see how much unused flexibility remains on the system after dispatch in each case.

Fuel and Energy Assurance

Fuel assurance considers the ability of a balancing authority to withstand disruptions to fuel supply chains and delivery mechanisms that hinder generator performance. The extreme cold weather of early 2014 challenged the long-standing paradigm that fuel would always be available to generators when needed and brought the concept of fuel assurance to the industry forefront.

PJM's Evolving Resource Mix and System Reliability paper in 2017, which evaluated several reliability attributes, defined fuel assurance as "the ability of a resource to maintain economic maximum energy output for 72 hours, based on the definition of fuel-limited resources within the PJM Manual 13: Emergency Operations Attachment C." The results of this study led PJM to explore a subset of these reliability attributes more deeply, resulting in the 2018 Fuel Security Analysis Report and continued work with stakeholders through the Fuel Security Senior Task Force (FSSTF).

By definition, solar and wind resources do not rely on traditional on-site fuels, and therefore the concept of fuel assurance does not apply. However, due to the inherent intermittent nature of their sources for energy, this does introduce the concept of managing energy assurance to account for variability in solar irradiance and wind speed, though geographic diversity of installations and a highly networked transmission grid can help to reduce the impacts of local weather conditions on overall grid reliability. Therefore, as renewable penetration increases, risks associated with fuel and energy assurance will also rise, especially as operators increasingly depend on nonrenewable generators – particularly flexible combined-cycle gas turbines, which also lack fuel assurance except in cases of firm delivery contracts or dual fuel capability – to produce power when sunlight and wind are limited.

These fuel and energy assurance concerns highlight the need to implement market design reforms to better align incentives with the operational needs of a system with high renewable penetration. Capacity market reform discussions are currently underway in the PJM stakeholder process in order to address these concerns.

In addition to market design changes, the deployment of ESRs can help mitigate intermittency issues that prevent solar and wind generation from having fuel assurance. Storage resources such as batteries can provide balancing across hourly timescales, as either stand-alone resources or in tandem with renewables as hybrid generators.

Because deployment of ESRs is still in a nascent stage, PJM cannot presently count on it to substantially mitigate the fuel assurance concerns associated with high penetrations of renewables. PJM will continue to monitor the development of storage technologies and continually assess their ability to provide support in this area.

Fuel Requirements for Black Start Resources

PJM initiated the Fuel Requirements for Black Start Resources (FRBSR) stakeholder group in 2019 to review the need to add fuel assurance requirements for some or all PJM black start resources to mitigate the impacts of non-fuel assured black start resources being unavailable during a system-wide blackout. The FRBSR initiative is currently on hiatus while PJM performs additional analysis to support initially proposed packages or to develop new packages. PJM will continue to evaluate impacts to system restoration as inverter-based resource penetration increases.

Black Start

Black start capability is necessary to restore the PJM transmission system following a system-wide blackout. PJM black start resources are able to self-start and close to a de-energized bus within three hours without electrical assistance from the grid or stay online and operate at reduced levels when automatically disconnected from the grid.

PJM black start resources must be able to control frequency and voltage, as they are the first resources online following a system-wide blackout. Black start resources provide power to pick up loads, energize transmission equipment and power PJM Critical Loads defined as units with a hot start time four hours or less, nuclear safe shutdown loads or electric-only gas compressors.

Inverter-based resources are not precluded from providing black start service as long as they can meet PJM's black start requirements. Currently, inverter-based resources are not classified as Critical Load.

Evaluating the impact of inverter-based resources and incorporating them into system restoration will become more important as state policies drive the transition away from traditional thermal resources.

System Stability

System stability is assessed from several perspectives:

1 | Transient (angular) stability

2 | Small signal stability, which is a degree of damping performance

3 | Voltage stability, which looks at dynamic voltage recovery performance

Inverter-based resources are asynchronously connected to the system, and their characteristics are quite different from traditional synchronous machines. Most fundamentally, stability for inverter-based resources is primarily judged by voltage performance. This is in contrast to rotor angle performance (δ), which is the typical quantity of interest in synchronous machines (rotor angle is not important because inverter-based resources are not truly synchronized with the grid).

Inverter-based renewable energy resources have several distinctive characteristics from a stability perspective:

- Since inverter-based resources are asynchronously connected to the system through power electronics interfaces, their inertia is normally small, which means less contribution to frequency stability. As their penetration level increases, the system is more prone to sharper frequency decline and a lower frequency nadir point given the same amount of generation loss.
- Unlike synchronous machines, inverter-based resources' low short-circuit contribution makes the system weaker from a voltage stability perspective.
- Inverter-based resources provide less reactive power support, which could make voltage recovery unhealthy after fault clearing.
- Distribution system-connected inverter-based resources are normally subject to less strict voltage/frequency ride-through requirements. When the amount of DER is substantial, the dynamics of DER along with load dynamics may need to be modeled in the simulation.

A weak transmission system exacerbates many of these issues. The typical measure of a point-of-interconnection strength is the short-circuit ratio (SCR). But measuring system strength with high power electronics penetrations may be more nuanced than simply using SCR. In the future, PJM may consider alternate weighted SCR methodologies to accurately gauge the strength of the system to determine where voltage stability issues are likely to occur.

When performing traditional stability studies, engineers use software that models the dynamic and transient interactions of generators. However, these models are inadequate for the types of voltage stability issues that arise with inverter-based resources. Thus, as renewable penetration increases, PJM may consider using Electromagnetic Transient modeling to ensure stability issues are properly identified.

Renewable Forecasting and Reliability Analysis

During PJM's industry research and outreach phase, predicting future renewable generation was found to be critical to near-term reliability analysis. Traditional reliability analysis focused on predicting, as accurately as possible, the expected system demand profile, or load curve, for a given day. Determining the load curve is highly complex and driven by both environmental factors as well as social behavior.

When performing reliability analysis, once this load curve is determined, generation is then dispatched via the economic stack. Known transmission and generation outages are analyzed, and operating plans are developed to ensure that all transmission facilities will be operated within their respective limits.

This past practice, however, requires the ability to actively schedule the generation in the economic stack. This is not the case for renewable resources for which fuel is not able to be actively scheduled, but rather is passively available based on ambient conditions (solar irradiance, wind speed, river levels). This introduces a new uncertainty that must be accounted for and adds a new dimension of complexity to PJM's reliability analysis, as well as generation and transmission outage coordination.

PJM has already started investigating enhancements to its operational assessments to account for the uncertainty in renewable output and the impacts on scheduled generation and transmission maintenance. Looking ahead to outage planning with renewables, PJM will need to be able to analyze planned and unplanned work with the most accurate forecasted data. This will help PJM operations personnel stay ahead of possible transmission constraints or capacity deficiencies.

In PJM's industry research, renewable forecasting came to the forefront as a crucial piece to maintaining reliability not just in outage planning, but also in analyzing most if not all of the reliability attributes discussed in this paper. Without an accurate forecast, reserve and regulation procurement will be much more difficult with the uncertainty of the intermittent resources. Accurate renewables forecasting will also be necessary for meeting capacity needs in the day ahead and for analyzing generation and transmission outages.

Other RTOs/ISOs use visual aids to help their operators gain situational awareness of their expected forecast. PJM plans to enhance its current visualization or situational awareness tools or add new tools that will be key to integrating renewables. PJM operators and engineers will need visual forecasting tools on solar and wind resources for real-time control. Integrating forecast data into existing reserve monitoring processes will be needed to help real-time generation dispatch and constraint control. Near-term studies will need to incorporate forecast data to prevent capacity deficiencies and transmission constraints.

Transmission Expansion

The Energy and Ancillary Services Market simulations performed did not include any transmission expansion that may be needed for reliability, but the results highlight the critical role of the interconnection in facilitating a reliable integration of renewables.

Additional scenarios would be necessary to incorporate impacts with future transmission upgrades that are likely needed to integrate the future renewable generation.

Separately, PJM has completed Phase 1 of an Offshore Transmission Study to identify transmission solutions across the PJM region to accommodate the PJM coastal states' offshore wind goals and PJM states' renewable portfolio standard (RPS) requirements. By synchronizing the planning of its coastal states' offshore wind deployment, PJM is able to identify transmission solutions that could present a more efficient and economic path for states to achieve their offshore wind policy objectives than if each state decided to independently integrate their offshore wind generation.

The Phase 1 component of this study analyzed five scenarios that were developed in collaboration with coastal state agencies within the PJM footprint. These five scenarios provide a high-level reliability assessment and cost estimate of how anticipated offshore wind generation and achieving current state RPS targets will impact the onshore PJM transmission system. It focused solely on identifying violations and upgrades to the current transmission system. The consideration of greenfield transmission solutions and offshore transmission facilities can be incorporated in later study phases.

The results presented in this study are to be considered advisory only and are meant to help inform policymakers as they advance their current and any future offshore wind policy endeavors. These results are also meant to serve as a starting point for any future scenarios that could be modeled in later study phases. In addition, while this study does identify the locations and costs of transmission upgrades, the results are not indicative of cost allocation to any ratepayer.

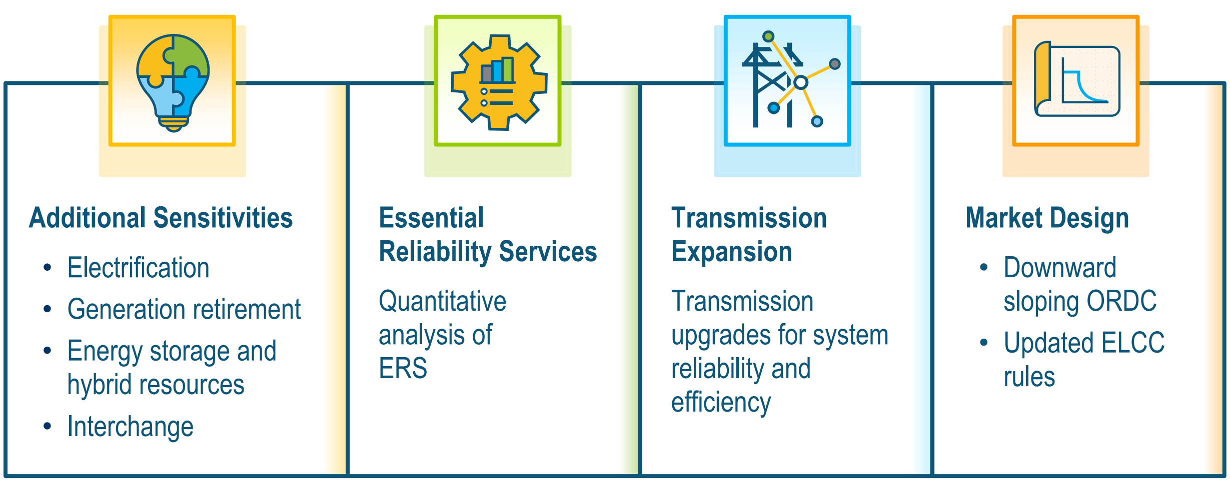
Moving Forward

PJM serves a region made up of diverse states with complex policies impacting the bulk electric power grid. These policies take many shapes, such as RPS, zero-emission credits, carbon cap-and-invest programs, energy efficiency incentives, electrification goals and offshore wind auctions. Cumulatively, these policies are driving the next energy transition in PJM, marked by an increase in renewable generation and energy storage, along with retirements of traditional thermal generation.

As we embark on this transition, it is important to recall that the grid has successfully endured multiple energy transitions. PJM and its members have reliably and effectively weathered these transitions due in large part to the value that comes with being a member of a Regional Transmission Organization with a robust planning process, efficient capacity market design, access to fuel diverse and geographically diverse generating resources, and a highly resilient network of transmission facilities that ensure the ability to deliver power to our customers.

PJM is proactively taking multiple steps to facilitate a reliable and cost-effective energy transition, focusing on improving the interconnection process, exploring potential enhancements to the capacity market and performing reliability studies to determine reinforcements needed to reliably deliver offshore wind in the PJM region.

This “living study” represents another tangible effort toward identifying gaps and opportunities in the current market construct and offering insights into the future of market design, transmission planning and system operations. The initial findings in this paper should not be regarded as expected outcomes but as bookends that will be refined as the study progresses. With that in mind, the following assumptions will be refined in the next phase of this multiyear effort:



LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 19

Responding Witness: Stuart A. Wilson

Q-19. Reference RTO Study. Provide any scenarios and/or the results of any scenarios that the Companies produced and/or ran but did not include in the published/reported RTO study. For any such scenarios, explain why the information was not published or reported in the RTO Study.

A-19. The Companies did not develop any additional scenarios.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 20

Responding Witness: Stuart A. Wilson

Q-20. Reference RTO Study. Provide a detailed table of benefit and costs considered by the Companies in the RTO Study, the best estimates of these quantities, and identify the quantities included and not included in the analysis with the corresponding reason(s) for inclusion or non-inclusion.

A-20. Appendix B of the RTO Study provides detailed tables of the benefits and costs, including the Companies' estimates of the annual values that were considered in the RTO analysis. The reasoning for including each of these items is included in the body of the RTO Study. No items were considered by the Companies for inclusion that were not ultimately included.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 21

Responding Witness: David S. Sinclair

Q-21. Reference RTO Study, Appendices B and C. Did the Companies request assistance or guidance from MISO and/or PJM in developing the Companies' model or estimates of production cost savings and/or capacity revenue resulting from joining the RTO? If yes, provide a detailed narrative of the Companies' request and fully discuss the assistance or guidance provided. Include in the response pertinent correspondence and any documents, analyses, or reports exchanged. If no request for assistance was made by the Companies, explain why not.

A-21. No. The Companies did not request assistance or guidance from MISO or PJM in developing the Companies' model or estimates of production cost savings or capacity revenue resulting from joining the RTO for several reasons.

First, the Companies have extensive experience with both RTOs. The Companies are non-transmission-owning members of both PJM and MISO, and are therefore well familiar with their policies, practices, and governance. Also, the Companies routinely transact in PJM and MISO (primarily selling into both markets) and have done so for more than a decade. Therefore, the Companies are not uninformed outsiders looking into the unknown complexities of RTOs from afar, but rather have extensive experience that informs their views and analyses.

Second, the Companies have repeatedly conducted RTO membership studies and analyses before the Commission. The Companies conducted the first such analysis in the context of the Commission's self-initiated investigation into the Companies' MISO membership and approved the Companies' MISO exit. In its final order in that proceeding in 2006, the Commission stated regarding the Companies' analysis ***versus the analysis presented by MISO***, "[T]he Commission finds that the LG&E and KU analysis is more credible and it provides a more reasonable indication of the likely outcome of exiting MISO and pursuing the TORC option."[17] The Companies conducted another RTO

[17] Case No. 2003-00266, Order at 17 (Ky. PSC May 31, 2006).

membership analysis in 2012,[18] again in 2018 in the context of their 2018 base rate cases,[19] and yet again in 2020 in response to the Commission's final orders in the 2018 rate cases.[20] In conducting their 2018 RTO analysis, the Companies supplemented their own analysis of and experience with MISO and PJM by having the Companies' personnel consult with RTO-member utilities in Kentucky to understand better their experiences in the RTOS. Therefore, the Companies' 2021 RTO membership analysis is the result of more than fifteen years of participation in and analyzing RTOs.

Third, both RTOs publish a voluminous amount of information concerning their rates, rules, terms and conditions for membership and participation in their respective real time and day ahead markets on their websites. The Companies keep abreast of this information and fully considered it in their screening analysis.

Fourth, the analysis, designed as a high-level screening analysis to determine if further investigation is warranted, showed further investigation is not warranted at this time.[21]

---

[18] Cases 2018-00294 and 2018-00295, Bellar Testimony Exhibit LEB-2, page 4 of 40 (Sept. 28, 2018) ("The Companies last performed a similar analysis in 2012, which showed that membership in MISO or PJM was not beneficial at that time").
[19] Cases 2018-00294 and 2018-00295, Bellar Testimony Exhibit LEB-2 (Sept. 28, 2018).
[20] Available at https://psc.ky.gov/pscecf/2018-00295/rick.lovekamp@lge-ku.com/03312020101025/Closed/2_LGE_KU_2020_RTO_Analysis_Study.pdf.
[21] See page 5 of the *2021 RTO Membership Analysis*.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 22

Responding Witness: Charles R. Schram

Q-22. Reference RTO Study, Appendix B. Did the Companies request assistance or guidance from MISO and/or PJM in developing and/or reviewing integrations costs? If yes, provide a detailed narrative of the Companies' request and fully discuss the assistance or guidance provided. Include in the response pertinent correspondence and any documents, analyses, or reports exchanged. If no request for assistance was made by the Companies, explain why not.

A-22. See the response to Question No. 21.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 23

Responding Witness: Charles R. Schram

Q-23. Reference RTO Study, Appendix B. How have the Companies addressed any uncertain integration, administration, uplift, and other costs, including uncertainty in the estimate for the cost and/or uncertainty in whether the cost is required? Include in the response a discussion of whether the Companies requested assistance or guidance from MISO and/or PJM in developing or obtaining estimates and the results of the request(s). If no request for assistance was made by the Companies to MISO and/or PJM for uncertain integration costs, explain why not.

A-23. See the responses to Question Nos. 18 (a) and 21.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 24

Responding Witness: Christopher D. Balmer / Charles R. Schram

Q-24. Reference RTO Study, Section 7.5 In lieu of speculating whether the Companies would lose Joint Party settlement revenue, did the Companies ask or attempt to negotiate with MISO and/or PJM concerning potentially favorable membership terms? Provide all correspondence with MISO and/or PJM relevant to the Companies' efforts in evaluating RTO membership. If the Companies did not ask or attempt to negotiate with MISO and/or PJM, fully explain why not.

A-24. No. The Companies reject the characterization of the well-founded assumptions in their RTO analysis as mere "speculation." See the response to Question No. 21; the same reasons concerning why the Companies did not ask PJM or MISO to contribute to the Companies' 2021 RTO analysis apply to this request.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 25

Responding Witness: Charles R. Schram

Q-25. Reference the RTO Study. For the Companies' withdrawal from MISO, please answer the following:

a. Identify the date upon which the Companies decided to withdraw from MISO.

b. From the date of the Companies' decision to withdraw from MISO, state the amount of time it took to complete the withdrawal and identify the end date or completion date of the withdrawal.

c. What were the direct expenses associated with the withdrawal from the date of the decision to withdraw to the completion date of the withdrawal (the costs that would not have been incurred by the Companies "but for" the withdrawal)?

d. State how the volume of wholesale trades changed upon the Companies' withdrawal from MISO.

A-25.

a. See the response to 1-18(l).

b. See the response to 1-18(l). The Commission approved the Companies' withdrawal from MISO on May 31, 2006,[22] and the Companies fully ended their MISO membership on September 1, 2006.[23]

---

[22] Case No. 2003-00266, Order (Ky. PSC May 31, 2006).
[23] *See, e.g.*, Case No. 2008-00251, Testimony of Paul W. Thompson at 18 (July 29, 2008) ("Most notably, the Companies fully ended their membership in the Midwest Independent Transmission System Operator, Inc. ('MISO') on September 1, 2006.").

c. The MISO exit fee was approximately $31 million.[24]

d. The Companies do not have information readily available concerning their wholesale transaction volumes from 2006. The Companies' off-system sales and purchases have varied over time for reasons that have nothing to do with MISO membership. Also, the Companies are able to transact inside and outside of RTO markets (including MISO), and have done so regularly since the Companies exited MISO. Therefore, it is not clear how the Companies' 2006 wholesale transaction volumes would be relevant even if the data were available.

   In addition, having high volumes of wholesale transactions does not necessarily correlate with benefits for customers. If the Companies were MISO members and did not self-schedule their units, they would have high wholesale transaction volumes. Whether those volumes would result in net benefits for customers is an entirely different question. When the Commission approved the Companies' exit from MISO, its order stated that exiting MISO would result in net benefits for customers.[25]

---

[24] *See, e.g.,* Case No. 2008-00251, Testimony of S. Bradford Rives at Exhibit 1, Reference Schedule 1.23 (July 29, 2008) (showing a MISO exit fee regulatory asset of $18,907,345 for KU); Case No. 2008-00252, Testimony of S. Bradford Rives at Exhibit 1, Reference Schedule 1.23 (July 29, 2008) (showing a MISO exit fee regulatory asset of $12,372,059 for LG&E).

[25] Case No. 2003-00266, Order at 17 (Ky. PSC May 31, 2006).

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 26

Responding Witness: Charles R. Schram

Q-26. Reference the RTO Study. Explain whether and how the Companies currently participate in MISO and/or PJM markets. Include in the explanation an identification of the benefits for the Companies and how these benefits are shared with the Companies' shareholders and customers, such as through allocation percentages of off-system sales, etc.

A-26. The Companies currently participate in the markets by making off-system sales when excess generation is available and market conditions are favorable and purchasing economy energy when market prices are lower than generation costs, all while optimizing the generation fleet and ensuring reliability. Off-system sales margins are shared 75% to customers and 25% to the Companies through the Off-System Sales Adjustment Clause. Economy purchases wholly benefit customers by reducing fuel expenses.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 27

Responding Witness: Charles R. Schram

Q-27. Reference the RTO Study. For the Companies' participation in MISO and/or PJM markets, provide the following:

a. Identify the analytical tools or resources used in support of the participation and identify their costs.

b. Identify the staff time used in support of the participation and identify the cost.

c. Identify the training necessary to participate in these markets and identify the corresponding cost of training.

d. Identify the estimated incremental or net increase in effort and costs for each of the above sub-parts, a., b., and c., associated with the Companies' full participation in each RTO, stated separately for each RTO.

A-27.

a. The Companies' trading personnel use each RTO supplier's web-based platforms for access to RTO published market information. Other external and internal resources are used to monitor other supporting information including weather and load. The costs for these tools and resources are immaterial compared to the revenues from off system sales.

b. The trading function is staffed around-the-clock with one trader spending a portion of their time monitoring market conditions, executing transactions, and scheduling power sales and purchases.

c. Trading personnel training for new traders is conducted in-house with significant on-the-job training with other experienced traders.

d. The Companies did not include a material change in effort or costs in the RTO study for trading activity associated with full participation in an RTO.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 28

Responding Witness: David S. Sinclair

Q-28. Reference the RTO Study. Under the assumption that the Companies will be short on capacity in 2028 by reference to the anticipated retirements, state the amount of time it would take for the Companies to study and prepare for joining an RTO versus other means of addressing a potential capacity shortfall in six (6) years. Include in the discussion the last date upon which the Companies could begin studying and preparing for joining an RTO in order to use the option for addressing a capacity shortfall in 2028.

A-28. The Companies have not developed a timeline for joining an RTO. Based on review of EKPC Case No 2012-00169, the Companies anticipate more than two years would be needed to conduct in-depth studies and prepare for integration into an RTO. However, a decision to join an RTO would be based on a broader set of criteria than just meeting the Companies' forecasted capacity needs in 2028. Instead, it would be informed by longer-term factors that clearly demonstrate an expectation for permanent cost savings for customers.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 29

Responding Witness: Charles R. Schram

Q-29. Reference the RTO Study. Have the Companies studied or otherwise analyzed other electric utilities in Kentucky that are members of an RTO concerning the costs and benefits of the utility's RTO membership? If yes, provide the results of the studies or analyses. Include in the response any correspondence between the Companies and any of these utilities.

A-29. As part of a prior RTO analysis,[26] the Companies only reviewed the primary circumstances and drivers that led to other Kentucky electric utilities joining RTOs. The Companies' current situation remains different from the circumstances and drivers that led those entities to join their respective RTOs.

---

[26] Cases 2018-00294 and 2018-00295, Bellar Testimony Exhibit LEB-2, Appendix D.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 30

Responding Witness: Charles R. Schram

Q-30. Reference the RTO Study. For each electric utility in Kentucky, by utility, that is a member of an RTO, state the reason(s) or factor(s), that the Companies identify as distinguishing that utility's costs and benefits from participation in an RTO as differing from the Companies' costs and benefits from participation in the same RTO.

A-30. See the response to Question No. 29.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 31

Responding Witness: Charles R. Schram

Q-31. Reference the RTO Study. Are the Companies aware of any efforts by other electric utilities in Kentucky with membership in an RTO to withdraw from the RTO? If yes, provide a description of the efforts known to the Companies.

A-31. The Companies are not aware of efforts by other utilities in Kentucky that are RTO members to end their membership in their respective RTOs.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 32

Responding Witness: Charles R. Schram

Q-32. Reference the RTO Study. Have the Companies obtained an RTO membership study performed by or on behalf of any other electric utility in Kentucky that is a member of an RTO. If yes, identify the utility and provide the study.

A-32. The Companies have reviewed the study performed by Charles Rivers Associates on behalf of EKPC that is available in Case No. 2012-00169.[27]

[27] http://psc.ky.gov/pscscf/2012%20cases/2012-0169/20120503_EKPC_Application_Volume%201.pdf

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 33

Responding Witness: Christopher D. Balmer

Q-33. Reference the Companies' System Average Interruption Duration Index ("SAIDI"), RTO Study Figure 9 and surrounding text pp. 18-19:

a. Is the Companies' calculation of their SAIDI consistent with how other utilities mentioned in the report calculate SAIDI? If no, explain why not and identify the differences in calculation.

b. What percentage of the failures included were due to distribution system issues versus generation inadequacy or transmission system failures? (State each percentage separately.)

c. Describe how the results would differ if the Companies did not exclude Major Event Days (such as a severe wind or ice storm)? If the Companies did exclude the Major Event Days, please provide adjusted graphs that reflect the inclusion of Major Event Days.

d. Explain why the Companies exclude Major Event Days.

A-33.

a. Yes. The Companies' calculation is consistent with how other utilities mentioned in the report calculate SAIDI.

b. Percentage of failures (SAIDI) by system are calculated in the table below:

Systems	2018	2019	2020
Distribution	2.3%	0%	0%
Generation	0%	0%	0%
Transmission	88.6%	97.7%	98.3%
Unknown*	3.7%	0%	1.6%
3rd Party Transmission	5%	0%	0%
Transmission Retail Customer	0.4%	2.3%	0.1%

c. The Companies did not perform analysis that included Major Event Days for the reason stated in the response to part (d).

d. The Companies follow the industry practice established by IEEE to exclude major events in order to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operations that would be overshadowed by the large statistical effect of major events.

LOUISVILLE GAS AND ELECTRIC COMPANY
KENTUCKY UTILITIES COMPANY

Response to Southern Renewable Energy Association's
Initial Request for Information
Dated January 21, 2022

Case No. 2021-00393

Question No. 34

Responding Witness: Charles R. Schram

Q-34. Reference the Companies' Equivalent Forced Outage Rate ("EFOR") and Equivalent Unplanned Outage Rate ("EUOR"), RTO study Figures 6 and 7 and surrounding text, page 16:

a. How do the Companies calculate EFOR?

b. How do the Companies calculate EUOR?

c. Is the Companies' calculation of EFOR and EUOR consistent with how Reliability First Corporation ("RFC") (as mentioned in the report) calculated EFOR and EUOR? If not, explain why not and identify the differences in calculation.

d. Explain why only CC and Steam units are included?

e. Describe how the results would differ if the Companies included all units. Include with the response to this sub-part a quantification of the difference in results.

A-34.

a. The Companies calculate EFOR in accordance with the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS). The GADS data reporting instructions can be found at: https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/2022_GADS_DRI.pdf

b. The Companies calculate EUOR in accordance with the North American Electric Reliability Corporation's (NERC) Generating Availability Data System (GADS). The GADS data reporting instructions can be found at: https://www.nerc.com/pa/RAPA/gads/DataReportingInstructions/2022_GADS_DRI.pdf

c. The RFC benchmark values shown in Figures 6 and 7 are calculated by the Companies, not RFC. The Companies obtain data from NERC GADS for similar sized units to the Companies' that are located in RFC. The Companies then apply the RFC values to the Companies' units' capacity to determine the benchmarks.

d. CC and Steam units were only included in Figures 6 and 7 as they are the only type of units considered by the Companies to be baseload.

e. The Companies do not have this data.