COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR APPROVAL OF A SOLAR POWER CONTRACT AND TWO RENEWABLE POWER AGREEMENTS TO SATISFY CUSTOMER REQUESTS FOR A RENEWABLE ENERGY SOURCE UNDER GREEN TARIFF OPTION 3	**)**	**CASE NO. 2020-00016**

TESTIMONY OF
DAVID S. SINCLAIR
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KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

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Section 1 – Introduction and Overview

Q. Please state your name, position, and business address.

A. My name is David S. Sinclair. I am Vice President, Energy Supply and Analysis for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies"), and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Have you previously testified before the Kentucky Public Service Commission ("Commission")?

A. Yes, I have testified before the Commission numerous times in a variety of cases.[1] I testified most recently in Case No. 2018-00294, *Electronic Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, and Case No. 2018-00295, *Electronic Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*.

[1] Among other cases, I testified before the Commission in the following cases: Case No. 2016-00370, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates and for Certificates of Public Convenience and Necessity*; Case No. 2016-00371, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates and for Certificates of Public Convenience and Necessity;* Case No. 2015-00194, *Investigation of Kentucky Utilities Company's and Louisville Gas and Electric Company's Respective Need for and Cost of Multiphase Landfills at the Trimble County and Ghent Generating Stations;* Case No. 2014-00371, *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*; Case No. 2014-00372, *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*; Case No. 2011-00161, *The Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00162, *The Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of Its 2011 Compliance Plan for Recovery By Environmental Surcharge*; Case No. 2011-00375, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate for the Construction of a Combined Cycle Combustion Turbine at the Cane Run Generating Station and the Purchase of Existing Simple Cycle Combustion Turbine Facilities From Bluegrass Generation Company, LLC in La Grange, Kentucky*; and Case No. 2014-00002, *Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of a Combined Cycle Combustion Turbine at the Green River Generating Station and a Solar Photovoltaic Facility at the E.W. Brown Generating Station*.

Q. Please describe your job responsibilities.

A. I have five primary areas of responsibility: (i) fuel procurement (coal and natural gas) and coal combustion residuals marketing for the Companies' generating stations, (ii) real-time dispatch optimization of the generating stations to meet the Companies' native load obligations, (iii) wholesale market activities, (iv) sales and market analysis and generation planning, and (v) technology research and analysis. As it pertains to this proceeding, the Generation Planning group prepared the Resource Assessment of the responses to the Companies' Request for Proposals for renewable generation ("Renewable RFP") and the Power Supply group negotiated the solar power contract with ibV Energy Partners, the winning bidder from the Renewable RFP, and the Renewable Power Agreements ("RPA") with Toyota Motor Manufacturing, Kentucky Inc., ("Toyota") and Dow Silicones Corporation ("Dow") as described under Option #3 of the Companies' Green Tariff. Green Tariff Option #3 enables large customers with greater than 10 MVA (or 10 MW as is appropriate) load to purchase renewable energy in excess of 10 MW nameplate AC through the Companies. This work was performed under my direction and overall supervision.

Q. What are the purposes of your testimony?

A. The purposes of my testimony are to describe the Companies' process for soliciting potential renewable energy sources, the methodology used to evaluate various responses to the Renewable RFP, the negotiations undertaken which resulted in the contract with Rhudes Creek Solar, LLC[2] ("Solar Power Contract"), and the major commercial attributes of the Solar Power Contract and RPAs.

[2] Rhudes Creek Solar, LLC is a limited liability company organized under the laws of Delaware and is wholly owned by ibV Energy Partners. It is authorized to transact business in Kentucky.

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibit to my direct testimony:

Exhibit DSS-1 Renewable RFP

Exhibit DSS-2 2019 Resource Assessment: Renewable RFP

Section 2 – Overview of the Renewable RFP

Q. Please describe the Companies' Renewable RFP.

A. The Companies issued the Renewable RFP on February 4, 2019 for 10 MW to 200 MW of renewable electrical power and energy with a preference for delivery starting no later than January 1, 2022. The Renewable RFP stated that the generation facilities must be in Kentucky or surrounding states, energy delivery be for a term from five to twenty years, and new generation assets were preferred. The Renewable RFP was sent to over 50 project developers, marketers, generation asset owners, and renewable energy trade groups. The Companies also issued a press release regarding the Renewable RFP[3] and placed a link to the Renewable RFP on their website to generate interest.[4] Responses to the Renewable RFP were due on March 29, 2019. A copy of the Renewable RFP is attached to my testimony as Exhibit DSS-1.

Q. Why did the Companies issue the Renewable RFP?

A. The Companies issued the Renewable RFP to systematically assess the cost of acquiring renewable energy delivered to its transmission system as a means to either reduce customers' energy costs or increase renewable generation at a modest

[3] Press Release, Louisville Gas and Electric Company and Kentucky Utilities Company, LG&E and KU Issue Request for Renewable Energy (February 4, 2019) (*available at* https://lge-ku.com/newsroom/press-releases/2019/02/04/lge-and-ku-issue-request-renewable-energy).

[4] Request for Proposals (RFP) to Sell Renewable Electrical Power and Energy (February 4, 2019) (*available at* https://lge-ku.com/sites/default/files/2019-02/RFP-February-2019.pdf).

incremental cost. As the Companies had recently proposed the establishment of a new "green tariff" for larger customers in their pending rate cases,[5] the responses to the Renewable RFP would provide real transactional opportunities to support interest in what became known as Green Tariff Option #3 if the Kentucky Public Service Commission approved the proposal.

Q. Did the Renewable RFP fundamentally differ from other RFPs the Companies had previously issued?

A. No. It differed from previous RFPs only in it was focused exclusively on renewable generation technologies, preferred new generation projects, and was not issued to meet a need for reliability or capacity. The Renewable RFP was focused on trying to acquire lower cost energy that could displace energy on a non-firm basis from the Companies' existing fossil fuel fleet. By focusing on energy only, the Companies were increasing the likelihood that renewable generation would be competitive.

Q. Why did the Companies prefer new generation projects?

A. The Companies primarily made this request in anticipation that potential Green Tariff Option #3 customers would prefer new projects to meet "additionality" attributes for renewable energy. Often, to meet corporate sustainability goals, large corporations wish to promote their procurement of renewable energy from a new renewable generation source so their actions are viewed as supporting "additional" renewable generation beyond business as usual generating assets that would be added regardless of their own participation.

[5] *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates,* Case No. 2018-00294 (April 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates,* Case No. 2018-00295 (April 30, 2019).

Q. How many responses were received to the Renewable RFP?

A. The Companies received 94 proposals from 16 respondents, including 71 initial proposals and 23 subsequent proposals that the Companies requested for revised sizes and terms. The proposals were primarily for solar energy located in Kentucky but included wind energy in Illinois and Ohio and battery storage options in Kentucky. The proposals ranged between 10 MW and 200 MW in size, between 10 and 30 years in term, and between $[redacted]/MWh and $[redacted]MWh in price, on a level price basis. Figure 1 shows the range of responses.

Figure 1 – Distribution of Initial Solar and Wind Proposals' Costs and Terms

Q. Please describe the process that was used to evaluate the responses.

A. The process used to evaluate the Renewable RFP is described in detail in "2019 Resource Assessment: Renewable RFP," which is attached to my testimony as Exhibit DSS-2. The Companies conducted their analysis of the Renewable RFP proposals in four phases:

1. A screening analysis was performed to identify the lowest cost proposals among the various technology types, nameplate capacity sizes, and contract terms;

2. The lowest cost proposals from the screening analysis were evaluated in a detailed production cost analysis to estimate each proposal's impact to system energy costs and from this evaluation a short-list of bidders was developed;

3. Best and final pricing and terms from the short-listed bidders were evaluated; and,

4. The top proposal was evaluated based on new fuel forecasts from the 2020 Business Plan and scenarios with CO_2 and renewable energy certificate ("RECs") pricing.

Q. Did the Companies conduct meetings with any of the short-listed bidders?

A. Yes.

Q. Please describe the nature and purpose of the meetings with these bidders.

A. The Companies met with the best two evaluated short-listed bidders. These meetings allowed the Companies to address such issues as land control, local and state permits, transmission interconnection, construction schedule, the overall project timeline; plans for operation and maintenance of the facility and how those plans would align with the guaranteed availability; and each bidder's general project development experience and capabilities.

Q. What was the Companies' criteria for determining the best proposal?

A. The primary factor was the proposal's potential to lower customers' energy costs over the life of the contract with the least risk. Since both finalists proposed new generation facilities, the Companies also focused considerable time and attention to each project's

attributes, the degree to which each developer had made progress on the project (e.g., land control), and the developer's track record for developing, financing, and constructing solar projects.

Q. What did the Companies select as the best proposal?

A. The Companies have negotiated a 20-year, 100 MW nameplate solar contract with a commercial operation target date of December 31, 2021 with ibV Energy Partners ("ibV") for a level price of $[redacted]/MWh. ibV Energy Partners is a wholly-owned subsidiary of ib vogt GmbH of Berlin, Germany that has developed, built and commissioned more than 80 projects while investing in and developing more than 2 GW of solar photovoltaic systems around the world. The actual contract counterparty will be Rhudes Creek Solar, LLC, which is wholly owned by ibV. ibV Energy Partners submitted its proposal for a 20-year, 100 MW nameplate solar contract during the third phase of the evaluation process in response to the Companies' request to short-listed bidders for proposals for a standardized set of contract capacities, terms and start dates.

Q. The 2019 Resource Assessment states at Section 3.3 (Finalist Evaluation) that ibV offered two possible project start dates, December 31, 2021 and December 31, 2022. Why did the Companies select the earlier project start date?

A. As I mentioned, the Companies stated in the Renewable RFP a preference for energy delivery beginning before January 1, 2022. This preference was driven by (i) the ability to provide renewable energy to potential Green Tariff Option #3 customers earlier and (ii) a desire to mitigate uncertainties that increase with the passage of time. For example, tax incentives for renewables are scheduled to decrease beginning in

2020. Also, as with any construction project, delay only allows the potential for issues to arise that could further delay the project. Furthermore, adding a resource sooner rather than later allows more time to learn how additional intermittent resources will impact the operation of the Companies' grid and generation fleet. This is especially important because many analysts are forecasting that solar and wind resources will become increasingly competitive with energy costs from coal generation. Despite the Companies' preference to begin receiving renewable energy earlier, the Companies' were willing to delay the start date if the delay produced material savings for customers.

Late in the discussions, ibV proposed delaying the project by one year and reducing the level price by [redacted]/MWh. This lower price level was not material, saving only about $[redacted] annually, and would have introduced unnecessary delay with all the associated delayed benefits and increased project risks that I just discussed.

Q. The 2019 Resource Assessment states at Section 3.3 (Finalist Evaluation) that ibV also offered both level and escalating pricing. Why did the Companies select the level pricing alternative?

A. The Companies chose the level price option to (i) ensure the Solar Power Contract's price in the future does not become perceived as out of line with potential new renewable generation should future solar generation costs decline as some analysts forecast, (ii) reduce the risk from long-term future fuel price escalation, (iii) reduce the risk from future REC price levels, and (iv) be more attractive to potential Green Tariff Option #3 customers with a preference for stable prices.

Q. Why are the Companies moving forward with only one proposal and for less than the full 200 MW that was requested in the Renewable RFP?

A. The 200 MW request in the Renewable RFP was a maximum nameplate capacity, not a minimum. This project is the Companies' first foray into a solar contract and we have selected the best proposal and project from the Renewable RFP. It so happens that this project is for 100 MW nameplate. While a second-best proposal and project could have been selected and pursued to reach an arbitrary size of 200 MW in total renewable generation, the economics, risk profile, and ability to contract with potential Green Tariff Option #3 customers were not sufficiently compelling at this time to pursue a second contract.

This project is a major step in solar generation for the Companies and the Commonwealth. If approved and constructed, it will be the one of the largest solar projects in Kentucky - 10 times larger than the Companies' Brown Solar project.

Adding 100 MW of nameplate solar to the Companies' system will allow the Companies to gain additional experience in the integration of large solar facilities into the existing generation and transmission systems. For example, having a second large solar site will allow the Companies to better study the impact of geographical diversity on the coincident intermittence of multiple renewable resources. Finally, assuming this project and Solar Power Contract are successfully implemented, and solar costs continue to moderate, then the Companies' experience from the Renewable RFP, the subsequent analysis, and Solar Power Contract negotiations and implementation will provide valuable insights for future renewable generation efforts.

Q. Will the Companies seek to add more renewable generation in the future?

A. The Companies are always seeking ways to lower their cost of providing energy to their customers, regardless of generating technology. So long as renewable generation permits the Companies to lower their energy costs, they will seek to add more renewable generation.

Q. Were there any lessons learned that might impact future efforts to acquire renewable generation?

A. Yes. The following factors clearly impacted pricing:

- Larger projects (100 MW or larger) were generally lower priced than smaller projects – in the range of $[redacted]/MWh to $[redacted]MWh.
- A longer contract term (20 years) was less expensive than a shorter contract term (15 years) – in the range of $[redacted]/MWh to $[redacted]/MWh.

Therefore, to get the best pricing, future Green Option #3 customers will likely want to be part of a larger project like this one and be willing to commit to 20-year term. Similarly, the Companies will likely emphasize project size and contract term the next time they issue a renewable RFP.

Q. Will any coal units be retired if the proposed Solar Power Contract is approved?

A. No. As demonstrated in the 2019 Resource Assessment, the energy from the Solar Power Contract is non-firm, must-take energy. Non-firm energy cannot be counted on to reliably serve load and, as the Resource Assessment demonstrates, the energy that is expected to be delivered will generally replace energy from higher cost resources. It is only in this context of non-firm, must-take energy that the Solar Power Contract is valuable to customers. Because the energy is "must-take," it is different from pure economy energy in that it is not dispatchable or guaranteed to be economic

in every hour. Without the reliability and grid services that are provided by the Companies' existing coal and natural gas fleet, the Companies would not move forward with any of the Renewable RFP proposals.

Q. Should the proposals that included battery storage be considered firm capacity?

A. Yes. However, as discussed in Section 3.2.1 of the 2019 Resource Assessment, the Companies evaluated the battery proposals as a dispatchable resource comparable to an existing natural gas-fired simple cycle turbine and were determined not to be economic. The analysis demonstrated that batteries are not currently economically viable to replace the Companies' existing dispatchable capacity. Furthermore, since battery storage can be charged with any type of generation, the more reliable the energy source for charging the battery, the more reliable the battery becomes. Hence, intermittent generation from wind and solar may not be the best source for reliably charging a battery.

Q. In the Companies' evaluation of the various proposals, did they assume that a long-term purchase power contract would be treated as long-term debt by the debt rating agencies?

A. No, not in the evaluation contained in the 2019 Resource Assessment. However, it is quite possible that the rating agencies may view the Solar Power Contract or any future long-term purchase power agreement as a debt equivalent. Should that be the case, the Companies will include in future evaluations any potential cost implications from treating long-term purchase power contracts as debt.

Q. What would be the impact to the Companies should rating agencies treat the Solar Power Contract or any future purchase power contracts as long-term debt?

A. If the Companies' took no actions to adjust their equity balance to offset a portion of the higher level of debt calculated by the rating agencies or adjust other rating criteria, then it is possible that the Companies' debt would be downgraded which would increase future borrowing costs. The Companies will monitor this issue and take the appropriate actions to mitigate the risk of any negative consequences from long-term purchase power agreements on future borrowing costs and our customers' rates.

Section 3 – Impact of the Solar Power Contract on Future Energy Costs

Q. How will energy from the Solar Power Contract be allocated between Toyota, Dow, and all customers?

A. For each interval of time (e.g., an hour), the energy received from the Solar Power Contract will be allocated as follows: 50 percent to Toyota, 25 percent to Dow, and 25 percent to all customers. Furthermore, of the portion allocated to all customers, 39 percent is allocated to LG&E customers and 61 percent is allocated to KU customers. This means that, of the 25 percent that is not allocated to Toyota and Dow, all LG&E customers will receive 9.75 percent and all KU customers will receive 15.25 percent of the energy in an hour. For example, if during an hour the Rhudes Creek Solar plant produced 60 MWh then Toyota would receive 30 MWh, Dow would receive 15 MWh, all LG&E customers would receive 5.85 MWh (= 60 MWh * 9.75%), and all KU customers would receive 9.15 MWh (= 60 MWh * 15.25%). Table 1 summarizes these allocations.

Table 1				
	All Customers	Green Tariff Option #3		Overall
		Toyota	Dow	
Total Solar Power Contract Allocation	25%	50%	25%	100%
Customer Assignment by Utility				
LG&E	39%	--	--	
KU	61%	100%	100%	
Utility Solar Power Contract Allocation				
LG&E	9.75%	--	--	9.75%
KU	15.25%	50%	25%	90.25%

Q. Will the Companies acquire renewable energy certificates ("RECs") with the energy purchased from the Solar Power Contract?

A. Yes. For each MWh of energy that the Companies purchase via the Solar Power Contract they will receive one REC at no additional cost.

Q. What will the Companies do with these RECs?

A. Absent an obligation in Kentucky or Virginia for renewable energy, the RECs associated with the energy that is delivered to all customers will be sold into the market, with the proceeds being returned to all customers, just as is currently done with the RECs created by Brown Solar. The RECs associated with the energy delivered to Toyota and Dow will be transferred to those two customers at no additional cost since they will be paying for that energy under their RPAs.

Q. Please describe the economic implications of the Solar Power Contract to all customers, excluding the energy that will be delivered to Toyota and Dow.

A. The Companies evaluated the Solar Power Contract under numerous scenarios, which considered the uncertainty in fuel prices, CO_2 emissions prices, REC prices, and the

timing of the retirement of the Companies' generating units. The net present value for revenue requirements ("NPVRR") for the portion of the Solar Power Contract allocated to all customers is summarized in Table 12 of the 2019 Resource Assessment and is reprinted below as Table 2 of my direct testimony. Over all the scenarios evaluated, the NPVRR in 2019 dollars ranges from [redacted] with an average of [redacted]. Only 6 of the 48 cases result in an [redacted] in NPVRR. In the 6 cases where the Solar Power Contract [redacted] NPVRR, the average [redacted] is [redacted], while in the 42 cases where NPVRR [redacted] the average [redacted] is [redacted]. Excluding the 24 high CO_2 emissions price cases, the overall average of the 24 zero CO_2 emissions price cases is [redacted]. In the 18 zero CO_2 emissions price cases that [redacted] NPVRR, the average [redacted] is [redacted], which compares favorably to the [redacted] in the 6 cases where NPVRR [redacted] In the scenarios with low fuel prices and zero CO_2 emissions prices, the NPVRR is favorable when the levelized REC price is [redacted]/REC or higher, a price level that is well below the over $10/REC average price achieved by the Companies in 2019 when they sold Brown Solar RECs. In the scenarios with base fuel prices and zero CO_2 emissions prices, the NPVRR is favorable when the levelized REC price is [redacted]/REC or higher.

Table 2						
Fuel Price Scenario	CO_2 Emissions Price Scenario	Unit Life Scenario	Levelized REC Price			
			$0/REC	$[redacted]/REC	$[redacted]/REC	$[redacted]/REC
Low	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
Base	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
High	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]

Q. Will the Solar Power Contract likely reduce the cost of energy for customers over its 20-year life?

A. Yes. While the renewable energy is not likely to result in lower energy costs in every hour of the Solar Power Contract's 20-year term, the Companies expect that the Solar Power Contract will reduce energy costs on a present value basis over the 20-year term, depending on commodity prices as I just discussed. RECs are currently trading between $6 and $7 per REC through 2021, but there is no liquid market for RECs to cover the period of the proposed Solar Power Contract and new laws regarding RECs may be enacted. However, if the current market price for 2021 RECs persists only through [redacted] or [redacted], the ibV proposal is favorable in the base fuel price and low fuel price scenarios, respectively, assuming zero CO_2 emissions prices. If REC prices are $0/REC, the likely worst-case scenario in any year will be that the price of energy from the Solar Power Contract is approximately $[redacted]/MWh greater than the Companies' avoided fuel cost and results in an increase in fuel costs of approximately $[redacted]

(25 MW x 8760 hours x 25% capacity factor x $[redacted]/MWh). Given that the Companies' annual fuel expense is approximately $800 million, this potential $[redacted] increase in fuel cost is insignificant.

Q. You have stated that the energy purchased under the Solar Power Contract will potentially reduce energy costs for customers by displacing higher cost energy. How much of this energy reduction will come from coal and natural gas generation?

A. All of it. Sections 3.2 and 3.4.2 of the Resource Assessment discuss how the avoided cost of the existing generation fleet was calculated and why the vast majority of the energy displaced by the Solar Power Contract will likely be coal generation. Even when natural gas generation from simple cycle gas turbines are on-line, the marginal heat rate of coal is higher than the gas turbines so that almost all the displaced energy is from coal generation. However, as coal units are assumed to be replaced by natural gas generation in the analysis and as gas prices increase, the percentage of Solar Power Contract energy that displaces coal generation decreases and the percentage of Solar Power Contract energy that displaces natural gas generation increases. Table 10 of the Resource Assessment shows the annual reduction in coal generation for each scenario evaluated.

Q. Approximately how much less coal would the Companies utilize as a result of purchasing energy from the Solar Power Contract?

A. The amount will vary based on the fuel and CO_2 price scenarios but averages 66,000 tons annually and ranges up to 101,000 tons annually. This compares to the approximately 12.5 million tons that the Companies currently utilize each year.

Q. Since the energy from the Solar Power Contract will be displacing fossil fuel-based generation, what is the anticipated impact on the Companies' CO_2 emissions?

A. The level of CO_2 emissions reductions depends primarily on the type of generation that is displaced, which varies based on the fuel and CO_2 price scenario. CO_2 emissions are approximately 1 ton/MWh for coal generation, 0.6 tons/MWh for simple-cycle combustion turbines, and approximately 0.4 tons/MWh for natural gas combined cycle units. Table 11 in the Resource Assessment shows annual CO_2 emissions reductions for each of the scenarios evaluated. Over the first several years of the Solar Power Contract, CO_2 emissions reductions range from 210,000 tons to 230,000 tons. By the end of the 20-year term, the range of CO_2 emissions reductions is 70,000 tons to 170,000 tons.

Q. Have the Companies included potential off-system sales impacts from the Solar Power Contract in their analysis?

A. No. Off-system sales are very small compared to total system costs and are highly uncertain due to market factors that are out of the Companies' control. Therefore, consistent with the Companies' prior practice for making resource planning decisions, the potential impact to off-system sales was not included in the evaluation.

Q. Was the process used to evaluate the Renewable RFP proposals materially different from the process the Companies have used in the past to evaluate alternative generation resources?

A. No. As in prior generation resource evaluations, the Companies performed an initial screening of the alternatives, followed by a detailed production cost analysis focusing

on multiple fuel and CO_2 emissions price scenarios to identify the option with the least-cost NPVRR. In this case, one slight difference is that the Companies did not explicitly run each resource through the PROSYM model but instead used output from PROSYM to calculate decremental costs in order to hold unit commitment constant. It was necessary to hold unit commitment constant due to the uncertain and intermittent nature of the solar and wind resources and the need to ensure system reliability each and every hour.

Q. Is it your opinion that the Solar Power Contract is a good value for customers?

A. Yes. The Companies' analysis indicates that the Solar Power Contract will likely reduce the cost of energy for customers and reduce CO_2 emissions with limited anticipated operational issues. The Solar Power Contract provides a stable energy price for its 20-year term at a level that is likely to be competitive with the Companies' coal and simple cycle natural gas generation in the long run. Given the existence and price levels of today's REC market, it is likely that the near-term higher energy cost of the Solar Power Contract can be more than offset with REC sales. Finally, it will provide useful information for integrating additional cost-effective renewable generation on the Companies' system in the future.

Section 4 – Overview of the Solar Power Contract

Q. Please describe the key attributes of the Solar Power Contract.

A. The Solar Power Contract is with Rhudes Creek Solar, LLC ("Seller"), a wholly owned subsidiary of ibV Energy Partners, LLC. The contract requires the solar generation facility to begin commercial operations no later than December 31, 2021 with limited extensions for force majeure and unforeseeable condition precedent

delays.[6] The as-available solar energy is priced at a level rate of [redacted] per MWh.[7] The contract contains an energy availability mechanism (called the "Availability Guarantee") to provide reasonable assurance that the facility will be maintained over the term of the agreement.[8] It requires the Seller to transfer the RECs produced by the facility at no additional charge to the Companies.[9] To ensure the Seller performs its contractual obligations, the contract requires the Seller to provide certain credit support.[10] Finally, to ensure the project is progressing in a timely manner toward the commercial operation date of December 31, 2021, the contract establishes various milestones related to state and local permitting, securing financing, and construction related activities. The failure to achieve these milestones permits the Companies to terminate the Solar Power Contract.[11]

Q. What is the process timeline that the parties negotiated assuming the Commission approves the Companies' application?

A. Sections 6.1 and 6.2 of the Solar Power Contract establish several milestones (termed "tiers" in the contract) that must be achieved before the Companies can receive energy from the solar facility in December 2021. First, and in parallel with the Companies' obtaining Commission approval, the Seller has until March 31, 2020 to finalize transmission line easements, receive an environmental assessment and site title report, and to obtain a ruling or other assurance from the Kentucky Department of Revenue regarding the facility taxation. Second, by June 30, 2020, the Seller must obtain all

[6] *Solar Power Contract at* art. 4.
[7] *Id*. at § 1.4 (defining Solar Energy Payment Rate).
[8] *Id.* at § 8.3
[9] *Id.* at § 7.1, § 7.3, and § 8.1.
[10] *Id.* at art. 11.
[11] *Id.* at art. 6.

siting, zoning, planning commission, and other governmental permits necessary for the facility's construction and operation. Third, by December 31, 2020, the Seller must have received approval for the facility from the Kentucky State Board on Electric Generation and Transmission Siting and received several items related to transmission system interconnection. Likewise, by December 31, 2020, the Companies must obtain the appropriate transmission service to deliver the energy from the solar facility to its customers. Finally, by March 31, 2021, the Seller must secure construction financing. Overall, approvals and permitting are expected to occur in 2020 with construction taking place through 2021.

Q. What are the Companies' rights and remedies if these milestones are not met?

A. Section 6.3 of the Solar Power Contract details each party's rights and available remedies if the milestones in Sections 6.1 and 6.2 are not met. Generally, a party can provide a notice of termination pending a specific cure period to remedy an issue. For example, if the Kentucky Department of Revenue has not issued a ruling regarding tax treatment of the solar facility by March 31, 2020, either the Buyers or the Seller may issue a notice of termination.

Q. What will happen if this Commission denies the Companies' application?

A. Assuming the reason(s) for the denial cannot be addressed in a manner mutually acceptable to all parties and the Commission, the Companies would terminate the Solar Power Contract and the RPAs with Toyota and Dow.

Q. Please describe the Seller's "availability" obligations to the Companies.

A. Section 8.3 of the Solar Power Contract sets forth the availability requirements that the Seller must meet. These requirements address the performance of the equipment,

not the absolute amount of energy produced. The solar facility will deliver energy commensurate with the amount of light available. Based on how solar photovoltaic technology works, energy will be produced when clouds do not block the sunlight – the contract does not require the seller to guarantee sunlight conditions. However, the Seller must apply prudent industry practices to maintain and repair equipment. Section 8.3 (B) of the Solar Power Contract describes the actions that can be taken by the Companies and the damages the Seller must pay if availability provisions are not met. Ultimately, the contract can be terminated as noted in Section 12.1 (C)(vii) if the availability provisions are not met for an extended period. For instance, if the facility is not performing to the Guaranteed Availability level, the Companies can issue an Availability Underperformance Notice at which time the Seller has 30 days to return the facility to the guaranteed level before paying liquidated damages. If underperformance continues, the Companies have the right to provide written notice of default and can terminate the contract subject to specific cure period provisions. Article 14 addresses the force majeure events that affect the issues that can be excluded from the availability provisions.

Q. Can the Seller assign the Solar Power Contract or sell the solar generation facility to others?

A. Yes. Article 19 addresses assignment and other transfer provisions. For example, assignment of the Solar Power Contract can occur provided the assignee assumes all the contract's obligations. The Companies may withhold their consent to a proposed assignment if the proposed assignee is adverse to the Companies in litigation or an

administrative proceeding or does not have experience operating and maintaining a utility scale solar facility.

Q. How is the obligation as a buyer being allocated between LG&E and KU?

A. Based on the energy allocation that I previously discussed, since Toyota and Dow are KU customers, the overall allocation of the Solar Power Contract is 9.75 percent to LG&E and 90.25 percent to KU.

Q. Do Toyota and Dow have any rights or responsibilities associated with the Solar Power Contract?

A. No. They are not a party to the Solar Power Contract, but their RPAs were developed with the Solar Power Contract's terms and conditions and the Companies' rights and obligations in mind.

Q. Based on your experience in negotiating power purchase agreements, have the Companies prudently negotiated the Solar Power Contract with an eye toward creating value for customers and protecting them from inappropriate risks?

A. Yes. I have personally been involved in wholesale energy markets for over 25 years and have either led or been on the team that negotiated numerous power purchase agreements as both a buyer and a seller. Based on this experience, it is my opinion that the Companies have negotiated a contract that creates value for customers and appropriately allocates risks between the Seller and the Companies.

Section 5 – Overview of Renewable Power Agreements

Q. How did Toyota and Dow advise the Companies of their interest in being Green Tariff Option #3 customers?

A. Both Toyota and Dow are among several existing and prospective customers that have expressed an interest in renewable energy to meet their own corporate sustainability

goals. Toyota has inquired about the purchase of renewables from the Company on several occasions over the past years while Dow expressed such interest last year after the Commission's approval of Green Tariff Option #3. Responses to the Renewable RFP allowed the Companies to present Toyota and Dow with concrete proposals, including draft pricing and terms, that led to each customer's interest in pursuing an RPA.

Q. Please describe the key attributes of the RPA.

A. The RPAs are structured for the Companies to pass through to Toyota and Dow all commercial terms, benefits, and risks associated with the Solar Power Contract. In other words, the RPAs do not subject the Companies or the Companies' other customers to any additional risks or benefits than they are already subject to under the Solar Power Contract. For example, the term of the RPA corresponds to the term of the Solar Power Contract; Dow and Toyota only receive energy from the Rhudes Creek Solar facility when that facility produces energy; and, Dow and Toyota pay the same price to the Companies for that energy as the Companies pay Rhudes Creek Solar.

While many of each RPA's provisions mirror those found in the Solar Power Contract, some provisions are unique to and appropriately found only in the RPA. For example, Section 2.8 addresses the energy payments for Solar Power Contract energy in excess of the customer's load during a 15-minute interval. This provision is necessary because the solar energy coming from the Rhudes Creek facility may sometimes be greater than the customer's load in a particular 15-minute interval. Since the customer cannot use the solar energy but is paying for it, the Companies

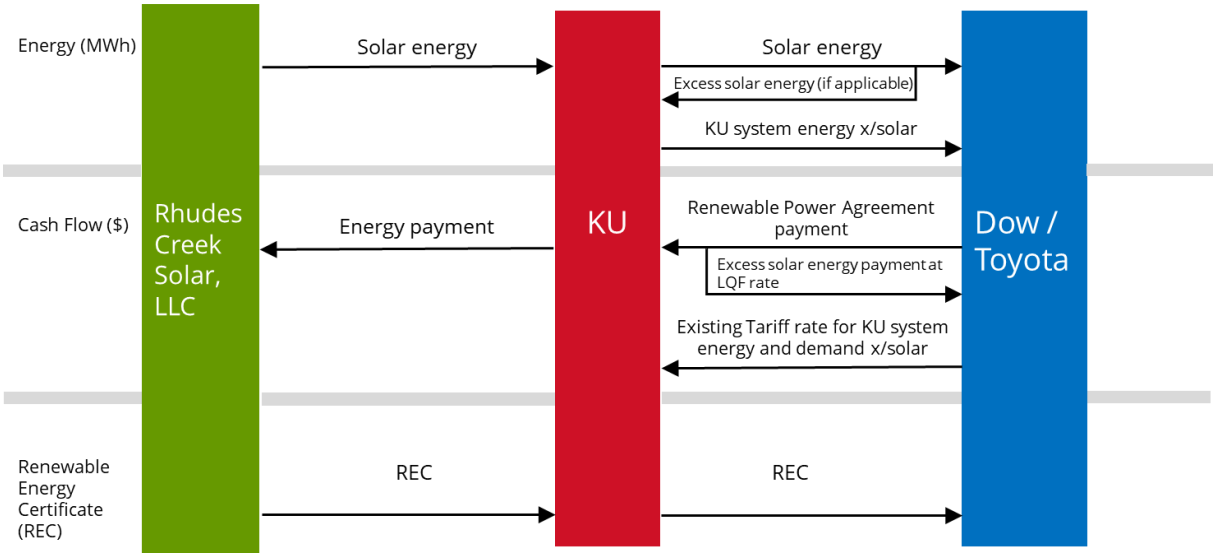
have agreed to buy back this energy at their avoided energy cost as set forth in the Large Capacity Cogeneration and Small Power Production Qualifying Facilities ("LQF") tariff rider.

To protect the interests of all customers for the entire 20-year term of the RPA, the Companies have negotiated a provision for financial support from [redacted] both Toyota and Dow [redacted]

Q. How will the energy from the Solar Power Contract impact the bills for Toyota and Dow?

A. Section 2.7 addresses how the energy that Toyota and Dow purchases under the RPA will impact the bills that each pays for its existing service. Figure 2 of my direct testimony illustrates the flow of energy, payments, and RECs between the Solar Power Contract, the Companies, and Toyota and Dow. It breaks down the RPA into three main attributes: energy flow, payments, and REC transfer. It shows that energy flows from the Rhudes Creek Solar facility to KU and then on to Dow and Toyota. All of this is measured on 15-minute intervals based on the current tariffs for Dow and Toyota. Figure 2 also shows that if Dow or Toyota is unable to utilize all of its share of solar energy in a 15-minute increment, its unused portion will be used to serve the load of all other customers. The Cash Flow section of Figure 2 shows the payments from Dow and Toyota being made to KU and then KU making the same payment to Rhudes Creek Solar. It also shows the payment by KU to Dow and Toyota for excess solar energy at the LQF rate. Lastly, the REC section shows the RECs being transferred by Rhudes Creek Solar to KU and then to Dow and Toyota.

Figure 2 – Energy, Payment, and REC Flow



Also shown in Figure 2 are the energy and payments from Dow and Toyota to KU for energy that is not coming from the Rhudes Creek Solar facility. Since the demand and energy consumption at the Dow and Toyota facilities will be measured as they have always been, each RPA establishes the mechanism by which the customer's existing billing volumes will be reduced in each 15-minute interval by the solar energy that is deemed delivered to it from the Rhudes Creek Solar facility via the Companies' system. This will result in Dow and Toyota purchasing less energy from KU at their existing tariff rates. The Base Demand component of their bills, however, will not change. The charges associated with the Base Demand billing component are for the transmission and distribution cost of providing service. Since the energy from the Rhudes Creek Solar facility must be delivered to Toyota and Dow, each must continue to pay for that portion of the system revenue requirements.

Q. Do the Companies' anticipate that the RPAs will reduce future electricity costs for Toyota and Dow?

A. Whether the RPAs will reduce the future electricity costs of Toyota or Dow is uncertain. Any reduction depends on the Companies' future rates for power supplied under Toyota's and Dow's existing rate schedules and how each customer's future load correlates with the Rhudes Creek Solar facility's energy production. During the negotiations of the RPAs, the Companies provided Toyota and Dow with projected solar energy production from the proposed Rhudes Creek Solar facility and calculated each entity's bill as if its RPA had been in effect. That information indicated that each entity had the potential to lower its electricity cost or would not experience a material increase in cost. Regardless of the bill impact, both Toyota and Dow will make progress toward meeting their corporate sustainability goals, which each considers an important objective. Each has full knowledge of the potential bill impact and has willingly entered into its RPA.

Q. Will the energy from the Solar Power Contract that is deemed delivered to Toyota and Dow impact the energy cost of all other customers?

A. Yes. By displacing energy that otherwise would have been generated, the Solar Power Contract energy deemed delivered to Toyota and Dow will reduce overall fuel costs for all customers.

Q. What happens if Toyota or Dow cease taking service from the Companies?

A. As I have previously described, Sections 2.7(b) and 2.8 of each RPA provide that any time the customer's share of energy from the Rhudes Creek Solar facility exceeds that customer's load during a 15-minute billing interval, the customer remains obligated to pay for that energy but the Companies will provide a bill credit to the customer for the excess energy at the LQF tariff rate. Therefore, should either Toyota or Dow close

its facilities, the guaranteeing affiliate would be financially responsible and would pay or receive the difference between the RPA price and the LQF rate and would also receive the RECs associated with the RPA energy. In other words, a complete closure of the facility is simply an extreme case of what may happen during any 15-minute billing interval during normal plant operations. This provision protects all customers from any additional costs.

Q. What would happen if the guaranteeing affiliate defaults on its obligations?

A. In that case, the Companies remain obligated to purchase the energy from the Rhudes Creek Solar facility and would search for new Green Tariff Option #3 customers to take the energy or use the energy to serve the load of all customers and sell the additional RECs, or both.

Q. Are the RPAs a good value for Toyota and Dow and all customers?

A. Yes. The RPAs cost-effectively meet the needs of Toyota and Dow for renewable energy with no material impact on energy costs to other customers. Furthermore, since each entity has freely executed its RPA, it is rational to believe that each finds the contract a good value.

Section 6 – Conclusion

Q. Please summarize why the Solar Power Contract and the RPAs with Toyota and Dow should be approved by the Commission.

A. The Solar Power Contract will likely lower customers' future energy costs, especially when considering the sale of RECs in the early years of the contract. At a minimum, it will bring price certainty to a small portion of future energy costs. The RPAs allow two of the Companies' larger customers to make cost-effective strides in meeting their corporate sustainability goals. The Solar Power Contract will allow the Companies to

reduce their CO_2 emissions in a cost-effective manner and to build on many of the lessons learned from the Brown Solar project about integrating solar generation by using the existing fossil fuel fleet to reliably integrate the 100 MW Rhudes Creek Solar facility - a project that is ten times larger than Brown Solar - into the Companies' grid.

Q. Does this conclude your testimony?

A. Yes.

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 foregoing testimony, and that 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 14th day of January 2020.

Notary Public

My Commission Expires:
Judy Schooler
Notary Public, ID No. 603967
State at Large, Kentucky
Commission Expires 7/11/2022

APPENDIX A

David S. Sinclair

Vice President, Energy Supply and Analysis
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
(502) 627-4653

Education

Arizona State University, M.B.A. -1991
Arizona State University, M.S. in Economics – 1984
University of Missouri, Kansas City, B.A. in Economics - 1982

Professional Experience

LG&E and KU Energy, LLC
2008-present – Vice President, Energy Supply and Analysis
2000-2008 – Director, Energy Planning, Analysis and Forecasting

LG&E Energy Marketing, Louisville, Kentucky
1997-1999 – Director, Product Management
1997-1997 (4th Quarter) – Product Development Manager
1996-1996 – Risk Manager

LG&E Power Development, Fairfax Virginia
1994-1995 – Business Developer

Salt River Project, Tempe, Arizona
1992-1994 – Analyst, Corporate Planning Department

Arizona Public Service, Phoenix, Arizona
1989-1992 – Analyst, Financial Planning Department
1986-1989 – Analyst, Forecasts Department

State of Arizona, Phoenix, Arizona
1983-1986 – Economist, Arizona Department of Economic Security

Affiliations

Consensus Forecasting Group (2013-present) - nonpartisan group of economists that monitor Kentucky's revenues and the economy on behalf of the governor and legislature.

Civic Activities

Serve on the Board of Junior Achievement of Kentuckiana

Graduate of Leadership Louisville (2008) and Bingham Fellows (2011)

LG&E and KU Energy LLC
Power Supply
220 West Main Street
Louisville, KY 40202
www.lge-ku.com

Chuck Schram
Director, Power Supply
502-627-3250

February 4, 2019

Subject: Request for Proposals (RFP) to Sell Renewable Electrical Power and Energy

Dear Colleague in the Development and Marketing of Renewable Electrical Power,

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (jointly the "Companies") are evaluating alternatives to provide additional least-cost renewable electrical power and energy to our customers, strengthening our renewable power supply portfolio and reducing the Companies' CO_2 emissions. The Companies are exploring adding up to 200 MW of renewable electrical power and energy, starting no later than January 1, 2022, that will qualify as a Designated Network Resource (DNR) through a Power Purchase Agreement. Preference will be given to new assets. The Companies will consider proposals that are reliable, feasible, and represent the least-cost means, including the cost for transmission service and required transmission upgrades, of meeting customers' requests for renewable electric power and energy. The respondent should make its proposal(s) as comprehensive as possible so that the Companies may make a definitive and final evaluation of the proposal's benefits to customers without further contact with the respondent. However, the Companies reserve the right to request additional information. Any failures to supply the information requested will be taken into consideration relative to the Companies' internal evaluation of cost, risk, and value.

This inquiry is not a commitment to purchase and shall not bind the Companies or any subsidiaries of LG&E and KU Energy LLC in any manner. The Companies in their sole discretion will determine which respondent(s), if any, they wish to engage in negotiations that may lead to a binding contract. The Companies shall not be liable for any expenses respondents incur in connection with preparation of a response to this RFP. The Companies will not reimburse respondents for their expenses under any circumstances, regardless of whether the RFP process proceeds to a successful conclusion or is abandoned by the Companies at their sole discretion.

1. **Background** – The Companies are issuing this RFP in order to evaluate renewable power as a means to provide least-cost power and energy to our customers in the future while meeting all laws and regulations. All proposals for renewable power (including any of the Companies' self-build options) will be evaluated in the context of meeting customers' load in a least-cost manner, with a preference for new assets. If the Companies determine that a proposal may be in the best interest of the Companies' customers, the Companies will enter into negotiations which may lead to the execution of definitive agreements. The Companies will consider all applicable factors in evaluating proposals, including, but not limited to, the following to determine the least-cost proposal(s): (i) the terms of the purchased power proposal; (ii) seller's creditworthiness; (iii) if applicable, the operating history or the development status of seller's generation facility, including, but not limited to, the site chosen, permitting, and the status of an interconnection to the transmission grid; (iv) the anticipated availability of the power; and (v) all other factors such as the cost of interconnection or transmission that may affect the Companies' cost to serve their customers.

2. **Requirements** - The Companies are interested in Power Purchase Agreements ("PPA"), for minimum quantities of 10 MW up to a total of 200 MW of nameplate power and associated energy from facilities in Kentucky or surrounding states. The power must be generated from a defined source, a specific unit or units that will qualify as a DNR. The delivery of power and energy should start no later than January 1, 2022. The Companies are interested in proposals ranging from five to twenty years. The Companies may procure less than 200 MW and may aggregate power and energy from multiple sellers. A seller offering power from a resource connected directly to the Companies' transmission system must conform to the Companies' Open Access Transmission Tariff (OATT) and must obtain an Interconnection Agreement for the facility in a timely manner.

3. **Key Terms and Conditions** - The respondent's proposal should include the proposed terms and conditions, including, where applicable to the respondent's proposal, among other things:

    3.1. Respondent will provide all pricing and terms that affect pricing, such as, but not limited to, escalators, transmission costs (if applicable), operation and maintenance cost, etc.

    3.2. Respondent will provide the annual and seasonal equipment availability, performance standards, and describe the required maintenance outage schedule.

    3.3. Respondent should address in their proposal its remedies for failure to meet any proposed performance standards and any production and other guarantees, if applicable.

    3.4. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their

customers' best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

3.5. The Companies termination of any contract rights will include, but may not be limited to: (i) failure to obtain all required regulatory approvals, (ii) failure to post or maintain required financial credit requirements, (iii) failure to meet key development and implementation milestones, (iv) failure to meet reliability requirements, and (v) failure to cure a material breach under the PPA.

4. **Metering and Monitoring** (Required Proposal Content) - The Companies may require real time metering and monitoring of the renewable generation resource. If so, the Companies desire, at the Companies' expense, to install equipment at the generator site to facilitate real time metering and monitoring. The respondent should state its desire and willingness to allow and cooperate with the Companies in establishing real-time monitoring and metering of generation.

5. **Ancillary Services** (Required Proposal Content) - Under a PPA, the Companies desire to have the unrestricted right to the renewable electric power and energy associated with the renewable generation being sold by the seller. Any sale of any ancillary service by the seller must not hinder the capacity availability of the facility and the facility's production of energy. The respondent should describe the ancillary service capabilities of the generation facility in its proposal, e.g. voltage support, how it plans on providing such services to another party, and how the sale of such service will not impact the capacity and associated energy in its proposal. If applicable, the respondent should describe any ancillary services, including, but not limited to, load following, spinning reserve, supplemental reserve, black start capability, frequency response, etc., that is being included in its proposal to the Companies.

6. **Pricing** (Required Proposal Content) - The pricing must be a delivered price to the Companies' transmission system. The Companies will be responsible only for Network Integrated Transmission Service (NITS) on the Companies transmission system. Prices must be clear and quoted in U.S. dollars. If pricing involves escalation or indexing, the details of such pricing, including the specific indices or escalation rates, must be included for evaluation.

6.1. The proposal must provide the product description and generation characteristics on the attached form. Pricing information can be provided on the form or separately in another format that is appropriate for the offer. If applicable, a projected hourly electric energy production profile for a typical year over the term of the proposal shall be provided electronically in an Excel spreadsheet. The respondent is encouraged to provide as much information as possible to aid in the evaluation of the offer. These attached data forms may be utilized in any filings with regulatory agencies (such as the Kentucky Public Service Commission) related to this RFP.

7. **Delivery** (Required Proposal Content) - The delivery point is the Companies' transmission system. Under a PPA, seller(s) will be responsible for providing firm transmission to the Companies' transmission system. The seller is responsible for all costs associated with transmission interconnections to the grid and point-to-point ("PTP") service to the delivery point. The seller will provide all studies, Interconnection Agreements, and PTP Transmission Reservations/Agreements. The seller is responsible for all transmission reservations, losses to the delivery point, and costs, including system upgrades up to the delivery point. TranServ International, Inc., 2300 Berkshire Lane North, Minneapolis, Minnesota 55441, is the Independent Transmission Organization that administers the Companies' OATT. Tennessee Valley Authority ("TVA") serves as the Companies' Reliability Coordinator ("RC"). For purposes of the Companies' evaluation of the proposals, the Companies may estimate any transmission costs that are not supported by the appropriate studies including the cost for deliverability and the associated voltage support to the Designated Network Load ("DNL") of the Companies. If all required transmission studies have not been completed, it is essential that the following information be provided in order for the Companies to evaluate the proposal:
    - Size of the unit(s)
    - Point of interconnection to the grid
    - Impedance of the generator step-up transformer
    - Transient and sub transient characteristics of the generator

8. **Environmental** - For the sale of renewable power to the Companies under a PPA, the seller will be responsible for obtaining all necessary permits and complying with their requirements for the life of the agreement, where permits are applicable for the product being sold. Failure to obtain or comply with any environmental permit or governmental consent would not excuse nonperformance by seller.

9. **Development Status** – Respondent shall provide a comprehensive narrative of the status of the development of any generation project intended to be used in a PPA with the Companies. Respondent's narrative shall include the following.
    - A comprehensive development and construction schedule,
    - A listing of all required permits and governmental approvals and their status,
    - A listing of all required electric interconnection and transmission agreements and their status,
    - A financing plan, and
    - A summary of key contracts (construction, major equipment, etc.), to the extent that they exist.

10. **Renewable Energy Certificates** – For the purpose of this RFP, renewable power is that electricity generated from renewable sources, including, but not limited to: solar, wind, hydroelectric, geothermal, landfill gas, biomass, biodiesel used to generate electricity, agricultural crops or waste, all animal and organic waste, all energy crops, and other renewable resources. The locations of these sources are limited to Kentucky and the

surrounding states: Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois. Sources must be certified for the creation of Renewable Energy Certificates as described below.

- A Renewable Energy Certificate ("REC") is the tradable unit which represents the commodity formed by unbundling the environmental-benefit attributes of a unit of green power from the underlying electricity. One REC is equivalent to the environmental benefits and attributes of one MWh of energy from a renewable resource. Eligible proposals must produce REC from facilities located in Kentucky, Indiana, Tennessee, Ohio, West Virginia, Virginia, Missouri, and Illinois.
- Eligible proposals must include RECs that are created from renewable facilities verified and approved by the proven renewable asset tracking systems associated with the major regional Independent System Operators ("ISO") operators. Applicable tracking systems are the PJM's Generation Attribute Tracking System ("GATS") or MISO's Midwest Renewable Energy Tracking System ("MRETS"). The legal ownership of every REC so created is recorded and tracked by GATS or MRETS to assure its authenticity and single ownership.
- The PPA will require the seller to create and transfer to the Companies the REC associated with the renewable power being sold. The respondent should also provide any additional information the respondent deems necessary or useful to the Companies relevant to the renewable power being sold to assist the Companies in making a definitive and final evaluation of the benefits of the respondent's proposal without further interaction between the Companies and respondent.

11. **Financial Capability** - Should the Companies elect to enter into an agreement with a seller who later fails to meet its obligations at any point in time, the Companies' customers may be exposed to the risk of higher costs. Therefore, the sellers will be required to demonstrate, in a manner acceptable to the Companies, the seller's ability to meet all financial obligations to the Companies throughout the applicable development, construction and operations phases for the term of the PPA. Under no circumstances, should the Companies' customers be exposed to increased costs relative to the cost defined in an agreement between the seller and the Companies.

    - At all times, the seller will be required to maintain an investment grade credit rating with either S&P or Moody's or have a parent guarantee from an investment grade entity that meets the approval of the Companies.

    - Upon execution of the PPA, the seller will be required to post a letter of credit ("LOC") to protect the Companies' customers in the event of default by the seller. The exact amount of a LOC will be subject to approval by the Companies based upon the Companies' models. If the Companies draw down the LOC amount at any time, the seller must replace the LOC to the original value within five days.

12. **RFP Schedule** - All proposals must be complete in all material respects and be received no later than 4 P.M. EDT on Friday, March 29, 2019. Email proposals must be followed up with a signed original within two business days.

RFP Issued	Monday, February 4, 2019
Proposals Due	Friday, March 29, 2019, 4 P.M. EDT
Evaluation Completed	Monday, May 20, 2019

Proposals will not be viewed until 4 P.M. EDT on Friday, March 29, 2019. After the evaluation of proposals is completed, the Companies will enter into negotiations on a timely basis if the Companies determine that a proposal is in their customers' best interests. Any subsequent contracts will be contingent on obtaining the necessary regulatory approvals.

13. Treatment of Proposals

13.1. The Companies reserve the right, without qualification, to select or reject any or all proposals and to waive any formality, technicality, requirement, or irregularity in the proposals received. The Companies also reserve the right to modify the RFP or request further information, as necessary, to complete their evaluation of the proposals received.

13.2. Respondents who submit proposals do so without recourse against the Companies for either rejection by the Companies or failure to execute an agreement for purchase of power and/or energy for any reason. Respondents are responsible for any and all costs incurred in the preparation and submission of a proposal and/or any subsequent negotiations regarding a proposal.

14. **Confidentiality** - As regulated utilities, it is expected that the Companies will be required to release proposal information to various government agencies and/or others as part of a regulatory review or legal proceeding. The Companies will use reasonable efforts to request confidential treatment for such information to the extent it is labeled in the proposal as "Confidential." Please note that confidential treatment is more likely to be granted if limited amounts of information are designated as confidential rather than large portions of the proposal. However, the Companies cannot guarantee that the receiving agency, court, or other party will afford confidential treatment to this information. Subject to applicable law and regulations, the Companies also reserve the right to disclose proposals to their officers, employees, agents, consultants, and the like (and those of its affiliates) for the purpose of evaluating proposals. Otherwise, the Companies will not disclose any information contained in the respondent's proposal that is marked "Confidential," to another party except to the extent that (i) such disclosures are required by law or by a court or governmental or regulatory agency having appropriate jurisdiction, or (ii) the Companies subsequently obtain the information free

of any confidentiality obligations from an independent source, or (iii) the information enters the public domain through no fault of the Companies.

15. **Contacts** - All responses should be emailed to: Feb2019RFP@lge-ku.com

Mailed responses should be sent to:

Chuck Schram, Director, Power Supply
LG&E and KU Energy LLC
Power Supply
220 West Main Street
Louisville, KY 40202

Phone: 502-627-3250

In closing, I look forward to your response by 4 P.M. EDT on March 29, 2019, and the possibility of doing business to meet the Companies' future power needs. Please contact me if you have any questions and would like to discuss further. For immediate concerns in my absence, please contact Linn Oelker, 502-627-3245.

Sincerely,

Chuck Schram
Director, Power Supply

LG&E and KU Renewable RFP Data Form

Note to respondent: Provide a separate term sheet for each different proposal or "Term of Contract". MW will be stated as an AC value at the delivery point.

Respondent _____

Product and Generation Characteristics:
Proposal Description_____
_____
_____
_____
Generation Source Description _____
Transmission Interconnection Point of the Source _____
Point of interconnection to the grid _____
Start Date and Term of Contract _____
Nameplate Amount _____ MW
Summer Capacity Amount _____ MW
Summer Maximum Dispatch Capacity Amount (if applicable) _____MW
Summer Minimum Dispatch Capacity Amount (if applicable) _____ MW
Winter Capacity Amount _____ MW
Winter Maximum Dispatch Capacity Amount (if applicable) _____MW
Winter Minimum Dispatch Capacity Amount (if applicable) _____MW
Annual production capacity factor _____ percent
Output in 10 minutes _____MW (if applicable)
Guaranteed minimum Ramp capability _____MW/minute (if applicable)
Control of Ramp capability: min ramp rate up: ___ MW/minute and min ramp rate down___MW/minute (if applicable)
Start-up time to minimum capability (if applicable) _____
Start-up time to maximum capability (if applicable) _____
Minimum run time (if applicable) _____
Minimum down time (if applicable) _____
Constraints on production time (if applicable) _____
Forced Outage Rate _____%
Guaranteed Availability _____
Planned Outage Schedule _____
Annual Production Factor _____
Projected hourly electric energy production profile for a typical year over the term provided electronically. Yes ___ No___

Pricing Information (provide a separate pricing form if applicable):
Pricing (Provide pricing in one of the following formats)

Power and Energy
1. Fixed price over the term _____($/unit)
2. Escalating Price Over Term_____ ($/unit) escalating at ____ % per year

Other charges, if any, for delivery to the LG&E and KU transmission system.

2019 Resource Assessment: Renewable RFP

PPL companies

Generation Planning & Analysis
December 2019

Contents

1. Executive Summary

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "the Companies") issued a request for proposals for renewable energy ("Renewable RFP") in February 2019 to evaluate renewable energy as a means of reducing customers' energy costs and to gather actionable alternatives to support interest from industrial customers in Green Tariff Option #3. Ninety-four proposals were received from 16 respondents, including 71 initial proposals and 23 subsequent proposals that the Companies requested from several respondents for revised sizes and terms.[1] The proposals were primarily for solar energy located in Kentucky, but several were for wind energy in Illinois and Ohio. Several of the solar energy proposals included a grid-connected battery storage option.

The Companies evaluated the Renewable RFP responses over numerous fuel price and CO_2 price scenarios and identified a proposal from ibV Energy Partners ("ibV") as most favorable for supporting interest in Green Tariff Option #3 and potentially lowering customers' future energy costs. The best ibV proposal resulted in the Companies negotiating a 20-year, 100 MW solar power purchase agreement including associated renewable energy certificates ("RECs") with a December 2021 start date at a level price of $[redacted]/MWh with an ibV special purpose entity named Rhudes Creek Solar, LLC ("Solar Power Contract"). The Rhudes Creek Solar facility will be constructed in Hardin County, Kentucky.

As the analysis of the Renewable RFP responses was progressing, the Companies met with industrial customers who had expressed interest in procuring renewable energy via the Green Tariff Option #3. As a result of these discussions, 50 percent of the Solar Power Contract has been contracted via a Renewable Power Agreement ("RPA") to Toyota Motor Manufacturing, Kentucky, Inc. ("Toyota") and 25 percent has been contracted via an RPA to Dow Silicones Corporation ("Dow"), both of which are KU customers. The remaining 25 percent of the Solar Power Contract will be used to serve all of the Companies' customers.

Based on all of the fuel price and CO_2 price scenarios, the impact on the future revenue requirements of the 25 percent of the Solar Power Contract serving all customers ranges from [redacted] (the net present value of revenue requirements ("NPVRR") in 2019 dollars over the 20-year contract term). The analysis shows that:

- The Solar Power Contract will save customers money in every case where there is a future price of CO_2;
- The level pricing of the Solar Power Contract has the potential to slightly increase annual fuel expense (likely less than [redacted] out of the Companies' total fuel expense of around $800 million) through the early 2030s, at which point the potential for escalating coal and natural gas prices make its energy less expensive than fossil fuel resources;
- To offset the potential for higher energy costs in the early years of the contract, the Companies will sell the RECs (excluding those transferred to Toyota and Dow) as is currently done with the RECs from the Brown Solar project. The 25 percent of Solar Power Contract energy allocated to

[1] All proposals received are listed in Appendix 6.1.

all customers will generate about 55,000 RECs annually. Thus, REC prices only need to average around [redacted] to offset the potential added cost of the solar energy. In 2019, the Companies sold Brown Solar RECs for over $10/REC. The [redacted] NPVRR case mentioned above results only if RECs have no value for the entire 20-year period – a risk that is very remote at the present time.

- Due to the level pricing in the Solar Power Contract, the need to sell RECs likely becomes very small and disappears altogether in the early 2030s given the risk of escalating coal and natural gas prices and the potential for CO_2 pricing.

Finally, the portion of the Solar Power Contract not allocated to Green Tariff Option #3 participants will be allocated 61 percent to KU and 39 percent to LG&E, based on each Company's share of forecasted energy requirements during daylight hours over the 20-year contract term. Because Toyota and Dow are KU customers, the overall allocation of the Solar Power Contract is 9.75 percent to LG&E and 90.25 percent to KU.

2. Renewable RFP

The Companies issued the Renewable RFP in February 2019 to over 50 project developers, marketers, generation asset owners, and renewable energy trade groups. The Companies also issued a press release[2] and placed a link to the Renewable RFP on the Companies' website to generate further awareness.[3] Proposals were requested for utility-scale (10-200 MW nameplate) renewable resources delivered to the Companies' transmission system for a period of between 5 and 20 years. The Renewable RFP did not specify a particular renewable generation technology but stated a preference for new renewable energy projects with delivery beginning no later than January 1, 2022.

The Companies issued the Renewable RFP to systematically assess the cost of renewable energy in Kentucky and evaluate renewable energy as a means to either reduce customers' energy costs or increase renewable generation at a modest incremental cost. In addition, the Renewable RFP was issued to provide real transactional opportunities to support interest in Green Tariff Option #3 should the Kentucky Public Service Commission ("Commission") approve that proposal in the Companies' then-pending rate cases.[4]

Sixteen companies responded to the Companies' Renewable RFP with 71 initial proposals with both level and escalating pricing options.[5] The proposals were primarily for solar energy located in Kentucky, but several were for wind energy in Illinois and Ohio. Five proposals included battery storage in

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[2] "LG&E and KU Issue Request for Renewable Energy," February 4, 2019. *See* https://lge-ku.com/newsroom/press-releases/2019/02/04/lge-and-ku-issue-request-renewable-energy.

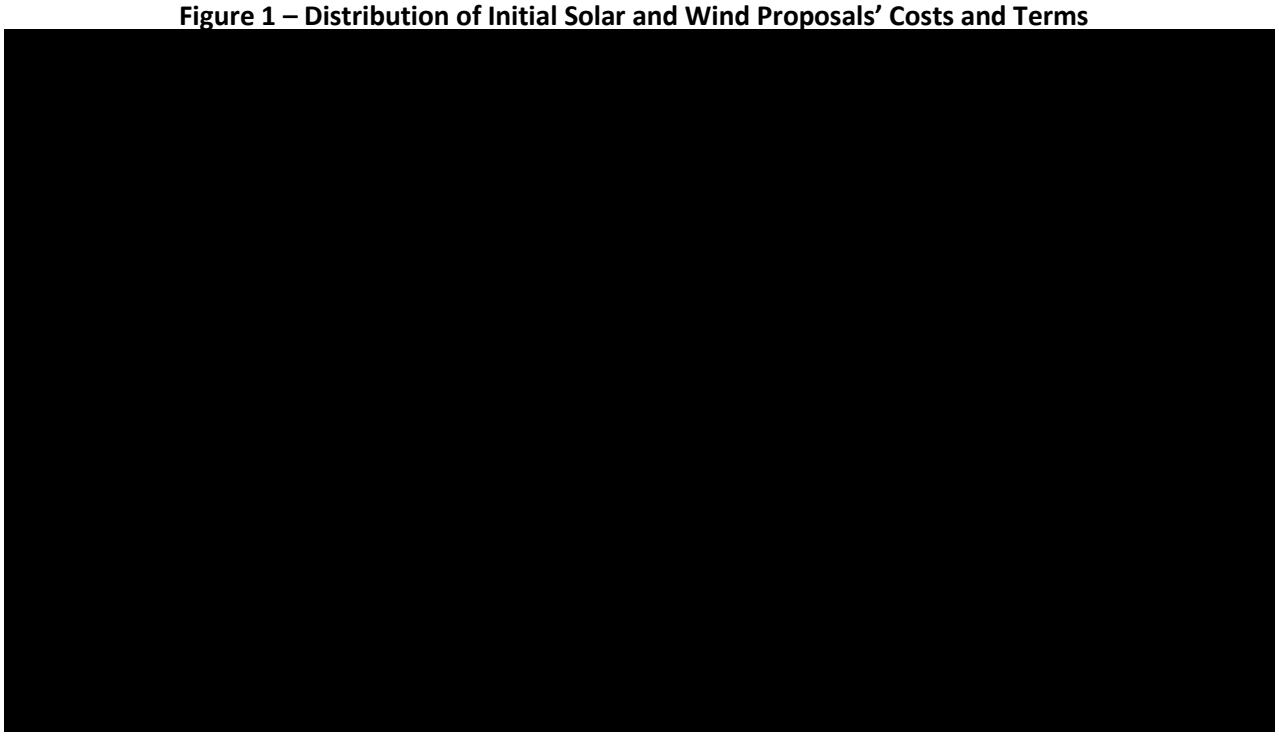
[3] "Request for Proposals (RFP) to Sell Renewable Electrical Power and Energy," February 4, 2019. *See* https://lge-ku.com/sites/default/files/2019-02/RFP-February-2019.pdf.

[4] *Electronic Application of Kentucky Utilities Company for an Adjustment of its Electric Rates,* Case No. 2018-00294 (April 30, 2019); *Electronic Application of Louisville Gas and Electric Company for an Adjustment of its Electric and Gas Rates,* Case No. 2018-00295 (April 30, 2019).

[5] Subsequent to receiving the initial proposals, the Companies requested additional proposals from several respondents for revised sizes, terms, and start dates, which brought the total number of proposals to 94.

Kentucky, one for a stand-alone battery and four for solar energy with a grid-connected battery storage option. Figure 1 plots the distribution of the proposed energy prices and terms of the initial solar and wind proposals. The proposals ranged between 10 MW and 200 MW in size, between 10 and 30 years in term, and between [redacted]/MWh and [redacted]/MWh in price, on a level price basis.[6] Battery storage is not a renewable resource but can be used to store energy for use on demand. Therefore, the Companies evaluated the battery storage proposals as a source of dispatchable energy and capacity.

Figure 1 – Distribution of Initial Solar and Wind Proposals' Costs and Terms



3. Analysis of Proposals

The Companies' analysis of the Renewable RFP proposals was completed in four phases. First, the Companies performed a screening analysis to identify the lowest-price proposals among the various technology types, nameplate capacity sizes, and contract terms**.** Second, the lowest-price proposals from the screening analysis were evaluated in a detailed production cost analysis to estimate each proposal's impact to system energy costs. During this phase of the analysis, the Companies followed up with a shortlist of the respondents to request best-and-final proposals as well as new proposals for a standardized set of contract capacities, terms, and start dates. In the third phase of the analysis, the Companies met with the top two respondents to discuss potential contract terms and project implementation plans in more detail. A clear frontrunner was identified through these discussions with whom the Companies initiated more formal contract negotiations. In the fourth phase of the analysis, the Companies evaluated the top proposal based on new fuel forecasts from the more recent 2020 Business Plan. Ultimately, the Companies entered into a contract with Rhudes Creek Solar, LLC (a

[6] In Figure 1, proposals with only an escalating pricing option are represented by a levelized price computed over the PPA term.

special purpose entity solely owned by ibV Energy Partners) for 100 MW of solar energy and associated RECs for 20 years.

As this analysis was being performed and after the Commission approved the Companies' application for the Green Tariff Option #3, the Companies met with industrial customers who had expressed interest in procuring renewable energy.[7] These discussions ultimately resulted in Renewable Power Agreements with Toyota Motor Manufacturing, Kentucky, Inc. ("Toyota") and Dow Silicones Corporation ("Dow"), both KU customers, based on the output of the Rhudes Creek Solar facility. However, because the level of Green Tariff Option #3 participation was unknown during most of the analysis, the revenue requirement impacts for each proposal in Section 3 was evaluated based on 100 percent of the proposal's energy being allocated to all customers. Green Tariff Option #3 participation reduces the allocation of costs and benefits to all customers, but it does not directionally impact the relative ranking of each proposal. Section 4 shows only the NPVRR impacts of the 25 percent of the Solar Power Contract allocated to all customers.

3.1. Screening Analysis

Given the large number of proposals, the Companies initially performed a screening analysis to identify the lowest-price proposals among the various technology types, nameplate capacity sizes, and contract terms. In this analysis, each proposal was assigned to one of three groups based on technology type, one of eight groups based on nameplate capacity, and one of six groups based on contract term (see Table 1).[8] Then, the proposal in each of the 17 groups with the lowest level or levelized escalating price as well as all proposals with a level or levelized escalating price less than [redacted] were selected for further evaluation.

Table 1 – Screening Analysis Groups

Category	# of Groups	Groups
Technology Type	3	Solar, Wind, Battery Storage
Nameplate Capacity	8	0-25, 26-50, 51-75, 76-100, 101-125, 126-150, 151-175, & 176-200 MW
Contract Term	6	10, 12, 15, 20, 25, and 30 years

The lowest-price proposals from the screening analysis are shown in Table 2. Solar proposals from ibV Energy Partners ("ibV") and [redacted] were the lowest-price proposals in more than one screening group.[9] The [redacted] from ibV was the lowest-price proposal overall. The lowest-price wind proposal was a [redacted] The [redacted] "), the [redacted] and the [redacted] were eliminated from further analysis based on their higher prices relative to other similarly-sized proposals of the same technology type.

[7] See Sheets 69 – 69.2 in LG&E's current electric rates at https://lge-ku.com/sites/default/files/lgereselectric.pdf and in KU's current electric rates at https://lge-ku.com/sites/default/files/kuelecrates.pdf.
[8] The Companies received six financial settlement proposals from [redacted] which did not include physical delivery of energy. The Companies did not evaluate these proposals.
[9] Section 6.2 in the Appendix contains a complete listing of the Screening Analysis results.

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Table 2 - Lowest Cost Proposals from Screening Analysis

Category	Group	Respondent	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Technology Type	Solar	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Wind	[redacted]	Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	Battery	[redacted]	Battery	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nameplate Capacity (MW)	0-25	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	26-50	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	51-75	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	76-100	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	101-125	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	126-150	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	151-175	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	176-200	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contract Term (Years)	10	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12	[redacted]	Wind	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	15	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	20	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	30	[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other <$30/MWh		[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	Solar	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

3.2. Detailed Production Cost Analysis

In the detailed production cost analysis, the Companies evaluated the impact on system energy costs for each of the proposals that passed the screening analysis using hourly avoided energy costs developed in PROSYM.[10] Then, the Companies followed up with the most competitive respondents to request and evaluate best-and-final proposals. The lowest-cost battery storage proposal was evaluated separately in PROSYM as a source of dispatchable capacity. The following assumptions from the Companies' 2019 Business Plan were included in this phase of the analysis.

- **Low, base, and high natural gas prices.** The low, base, and high natural gas prices assumed in this analysis, as well as the coal prices, are shown in Table 3.
- **Zero price for carbon dioxide ("CO_2") emissions.**[11] No CO_2 emissions prices were assumed at this early stage in the evaluation given the uncertainty that exists regarding possible future CO_2 regulations. Furthermore, excluding CO_2 emissions prices allowed the Companies to focus the analysis explicitly on avoided energy costs based on known regulations.
- **Zero price for RECs.** No REC price was included in this phase so the analysis could focus on avoided energy costs.[12]
- **65-year unit life.** The Companies' existing generating units are assumed to retire when they reach 65 years of age and replaced by 1x1 natural gas combined cycle ("NGCC") units (368 MW each) as needed to maintain the Companies' minimum target reserve margin.
- **No modeled change to unit commitment.** Due to the intermittent nature of renewable generation and the size of the proposals being evaluated, the Companies assumed no change to the 2019 Business Plan's modeled commitment of existing units and no need for added renewable integration costs including possible transmission system upgrades.
- **Generation profile correlated to weather.** The hourly generation forecast for each proposal was developed by the respondents using the same weather assumptions that the Companies used to develop their hourly load forecast.
- **No off-system sales**. Generation for off-system sales is very small compared to native load energy requirements and highly uncertain due to market factors that are out of the Companies' control. Therefore, consistent with the Companies' prior practice for making resource planning decisions, the potential impact to off-system sales was not considered in the analysis.

[10] PROSYM is the Companies' detailed production cost modeling software and is provided by ABB.
[11] A scenario that includes a forecasted price for CO_2 emissions was included in the 2020 Business Plan update, as discussed in Section 3.4.
[12] The Companies expect to reduce customers' costs by selling the RECs associated with any renewable energy that is allocated to all customers and returning the funds to customers as they currently do with RECs from Brown Solar. However, the RECs for energy assigned to Green Tariff Option #3 customers will be transferred to those customers at no cost.

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Table 3 – 2019 Business Plan Fuel Prices (Nominal $/MMBtu)

	Natural Gas (Henry Hub)			Coal (Illinois Basin, FOB Mine)
	Low	Base	High	
2020	[redacted]	[redacted]	[redacted]	[redacted]
2021	[redacted]	[redacted]	[redacted]	[redacted]
2022	[redacted]	[redacted]	[redacted]	[redacted]
2023	[redacted]	[redacted]	[redacted]	[redacted]
2024	[redacted]	[redacted]	[redacted]	[redacted]
2025	[redacted]	[redacted]	[redacted]	[redacted]
2026	[redacted]	[redacted]	[redacted]	[redacted]
2027	[redacted]	[redacted]	[redacted]	[redacted]
2028	[redacted]	[redacted]	[redacted]	[redacted]
2029	[redacted]	[redacted]	[redacted]	[redacted]
2030	[redacted]	[redacted]	[redacted]	[redacted]
2031	[redacted]	[redacted]	[redacted]	[redacted]
2032	[redacted]	[redacted]	[redacted]	[redacted]
2033	[redacted]	[redacted]	[redacted]	[redacted]
2034	[redacted]	[redacted]	[redacted]	[redacted]
2035	[redacted]	[redacted]	[redacted]	[redacted]
2036	[redacted]	[redacted]	[redacted]	[redacted]
2037	[redacted]	[redacted]	[redacted]	[redacted]
2038	[redacted]	[redacted]	[redacted]	[redacted]
2039	[redacted]	[redacted]	[redacted]	[redacted]
2040	[redacted]	[redacted]	[redacted]	[redacted]
2041	[redacted]	[redacted]	[redacted]	[redacted]
2042	[redacted]	[redacted]	[redacted]	[redacted]
2043	[redacted]	[redacted]	[redacted]	[redacted]
2044	[redacted]	[redacted]	[redacted]	[redacted]
2045	[redacted]	[redacted]	[redacted]	[redacted]
2046	[redacted]	[redacted]	[redacted]	[redacted]
2047	[redacted]	[redacted]	[redacted]	[redacted]
2048	[redacted]	[redacted]	[redacted]	[redacted]
2049	[redacted]	[redacted]	[redacted]	[redacted]
2050	[redacted]	[redacted]	[redacted]	[redacted]

The energy from each proposal was evaluated as non-firm, must-take energy since it is dependent on sunlight, cloud, or wind conditions and is not dispatchable. This means that system reliability is still ensured by the Companies' existing fleet of dispatchable resources. By relying on the existing fleet for reliability and only looking at decremental energy costs, the Companies are evaluating intermittent generation like wind and solar in the most favorable way possible. The Companies projected hourly energy cost savings for each proposal in the natural gas price scenarios by computing the cost of energy from the Companies' dispatchable resources that would be displaced by the renewable generation.

Because the Companies' resources are committed and dispatched economically, the renewable generation will displace energy in each hour from the Companies' highest-cost resources.[13]

It is important to note that while the analysis at this phase utilized three natural gas price scenarios, only in the "High" case did natural gas prices materially affect the financial results because coal generation was almost always the marginal resource when evaluating new solar and wind resources. This condition occurred for three reasons:

1. This phase assumed a 65-year unit life. Until Brown 3 is retired in 2036 and Ghent 1 is retired in 2039 - near the end of the 20-year analysis period - the only natural gas-fired combined cycle unit in the Companies' fleet is Cane Run Unit 7. This means that gas prices would need to be high enough before 2036 to force Cane Run 7 to be the marginal unit above coal-fired units.

2. While the average heat rates of coal units and simple cycle gas turbines ("CT") may be similar, the marginal heat rate of a coal unit is often much greater, meaning that if a CT has been started, it will likely be loaded before a coal unit because the next MW is cheaper. Thus, if solar or wind is added to the system, it will be the coal unit that backs down first to accommodate it rather than the CT. Furthermore, CTs do not run many hours in a year – typically less than 1,000 hours annually – so this impact will be somewhat limited.

3. Given the 65-year life assumption in this phase and points #1 and #2 above, the vast majority of the hours in a year will have coal as the marginal generation source because Cane Run Unit 7 is lower cost or there are no other gas resources online.

The NPVRR for each screened proposal was calculated by subtracting the present value ("PV") of its projected hourly energy cost savings from the PV of its projected hourly purchase costs. Then, this difference was levelized over the proposal's projected generation to normalize the results on a $/MWh basis. This normalized metric ("levelized NPVRR") allows for a direct comparison of the cost effectiveness of proposals with different nameplate capacities and terms. No integration costs were considered as it was assumed that the load following capabilities of the Companies' existing resources could maintain reliability while supporting the intermittent nature of the renewable energy proposals and that no material transmission upgrades would be required.

Table 4 contains the detailed production cost analysis results for proposals that passed the screening analysis. The results are ranked by the levelized NPVRR ($/MWh) from the base natural gas price scenario; all pricing options for the proposals are listed separately. Negative levelized NPVRR values indicate that a proposal would be expected to lower system energy costs for customers over the proposal's term. Because this phase of the analysis assumed zero REC prices, the levelized NPVRR for proposals with an unfavorable NPVRR is the levelized REC price on a $/MWh basis that would be required to make the NPVRR zero.

[13] A more detailed discussion of this process along with the average annual energy cost savings for each natural gas price scenario is included in Section 6.3.

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Table 4 – Detailed Production Cost Analysis Results for Proposals that Passed Screening Analysis (Zero REC Prices; Negative values indicate savings and positive values indicate greater costs)

	Respondent	Levelized NPVRR ($/MWh)			Price ($/MWh)	Nameplate Capacity (MW)	Term (Years)	Start Year (Dec.)
		Low Gas	Base Gas	High Gas				
Solar	[redacted]							
Wind	[redacted]							
Solar	[redacted]							

Based on these results, the Companies requested any updates in generation profiles and pricing from [redacted] ibV, [redacted].[14] In addition, the Companies requested these respondents provide new proposals for a standardized set of contract capacities, terms, and start dates to ensure that each respondent's proposed capacity and term were most favorable and to improve comparability among the different respondents.

Table 5 contains detailed production cost analysis results for all proposals from the shortlist of respondents, including updates to generation profiles and pricing where applicable, and ranks the results by the levelized NPVRR ($/MWh) from the base natural gas price scenario. Compared to the wind proposals, the lower-priced solar proposals have the higher potential to reduce costs for customers. While wind generation would generally be expected to have a higher capacity factor compared to solar, the generation typically occurs more in off-peak hours, which tend to have lower avoided costs compared to the on-peak daytime hours when solar generation occurs. Section 6.5 shows a comparison of typical generation profiles of wind and solar.

[14] Because the [redacted] and [redacted] proposals were similarly priced, the Companies chose to follow up with [redacted] to include a wider range of nameplate capacities.

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Table 5 – Detailed Production Cost Analysis Results for Proposals from Shortlist of Renewable RFP Respondents (Zero REC Prices; Negative values indicate savings and positive values indicate greater costs)

	Respondent	Levelized NPVRR ($/MWh)			Price ($/MWh)	Nameplate Capacity (MW)	Term (Years)	Start Year (Dec.)
		Low Gas	Base Gas	High Gas				
Solar	[redacted]							
Wind	[redacted]							
Solar	[redacted]							
Wind	[redacted]							
Solar	[redacted]							

Even with zero REC prices, the [redacted] and the [redacted], [redacted] ibV proposals are favorable in each natural gas price scenario. Based on these results, [redacted] and ibV were deemed finalists for further due diligence and evaluation.

During this due diligence phase, ibV provided two new proposals for a 20-year, 100 MW solar power purchase agreement at prices lower than their [redacted] proposal:

- December 2021 in-service date at a level price of $[redacted]/MWh (or $[redacted]/MWh, escalating at [redacted] percent per year)
- December 2022 in-service date at a level price of $[redacted]/MWh (or $[redacted]/MWh, escalating at [redacted] percent per year)

These additional proposals were evaluated in the final phase discussed in Section 3.3 below.

3.2.1. Analysis of Battery Storage Proposal

All proposals for battery storage involved battery storage connected to the grid. None involved batteries dependent on the availability of a renewable resource to charge. For this reason, the Companies evaluated the lowest-priced battery storage proposal separately as a dispatchable resource. The price of the lowest-priced battery proposal was $[redacted]/kW-month level (or $[redacted]/kW-month escalating at [redacted] percent per year) for a [redacted] MW, [redacted] MWh battery, which equates to an annual capacity cost of $[redacted].

This proposal was eliminated from further consideration because of its high capacity cost. As a point of comparison, the Companies' combustion turbines ("CTs") at the Brown Station (Brown Units 5, 8, 9, 10, & 11) have a levelized "stay-open" fixed cost of $0.96/kW-month, which equates to an annual capacity cost of between $1.4 and $1.5 million.[15] With [redacted], these CTs each provide more than six times the capacity of the proposed battery and the ability to provide energy for a longer duration. Even though the Companies were not seeking capacity from the Renewable RFP, this analysis demonstrates that the battery proposals were not currently economically viable to replace the Companies' existing simple cycle gas turbine capacity, even when the batteries in these proposals could be reliably charged from the grid and were not dependent on intermittent renewable generation to charge them.

3.3. Finalist Evaluation

In making a final decision regarding the various proposals, the Companies had to select among four parameters: contract term, nameplate capacity, start date, and level vs. escalating energy price.

As to the issue of contract term, Table 6 shows that for each finalist, a 20-year term resulted in a lower price by between $[redacted] and $[redacted]/MWh compared to the 15-year term. Therefore, all 15-year proposals were rejected.

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[15] The Companies' 2018 Integrated Resource Plan ("IRP") shows that each of the Brown Units 5, 8, 9, 10, & 11 (121-130 MW each) have an annual stay-open cost of $11.5/kW-year ($0.96/kW-month = $11.5/kW-year / 12 months/year). *See* Table 9 on page 17 of the "2018 IRP Reserve Margin Analysis," located in Volume III of the 2018 IRP at https://psc.ky.gov/pscecf/2018-00348/rick.lovekamp%40lge-ku.com/10192018102925/5-LGE_KU_2018_IRP-Volume_III.pdf.

Second, increasing the nameplate capacity of the project also resulted in a lower price from each finalist. For example, [redacted] made proposals of [redacted] MW, [redacted] MW, and [redacted] MW with [redacted]-year level pricing of $[redacted]/MWh, $[redacted]/MWh, and $[redacted]/MWh, respectively, beginning [redacted]. Similarly, ibV proposed a [redacted] MW, [redacted] MW, and 100 MW contract with 20-year level pricing of $[redacted]/MWh, $[redacted]/MWh, and $[redacted]/MWh, respectively, beginning in December 2021. Because the interest in Green Tariff Option #3 by Toyota and Dow was 75 MW, increasing the size of the potential contract to 100 MW would result in not only lower pricing for them, but also create a volume of energy that could be used to lower future energy costs for all customers. Therefore, the Companies focused on the 100 MW proposals.

Third, as stated in the Renewable RFP, the Companies preferred energy delivery beginning before January 1, 2022. This preference was driven by (i) what we had been hearing from potential Green Tariff Option #3 customers for a preference of renewable energy sooner rather than later, and (ii) a desire to mitigate uncertainties that increase with the passage of time regarding the availability of tax incentives for renewables, the market for solar RECs, and project development in general. Furthermore, entering into a contract with a 2021 in-service date did not preclude the Companies from seeking additional renewable generation. While a preference existed to begin receiving renewable energy earlier, the Companies were willing to delay the start date if there was a material savings for customers. Setting aside the NPVRR $/MWh metric and looking only at the absolute price that customers would pay each year, the [redacted] proposal to provide energy beginning in [redacted] was priced at [redacted] while waiting another year would have reduced the price by only $[redacted]/MWh to $[redacted] a savings of less than $[redacted] annually. Similarly, ibV's 100 MW, 20-year proposal to begin service in December 2021 was priced at $[redacted] as compared to $[redacted] by waiting a year – [redacted] just $[redacted]/MWh or about $[redacted] annually. Therefore, with such a small savings potential, the Companies opted to focus on the earlier project start date of December 2021.

Finally, the decision between level and escalating contract energy prices focused on risk mitigation. While an escalating energy price would make the potential for fuel savings greater in the near term, it would place greater emphasis on the future escalation rates of coal and natural gas as well as the potential retirement dates for coal units. Also, as discussed in detail in Section 3.4.1, an escalating contract price potentially requires some level of REC prices throughout the 20-year contract term to create energy savings for customers. In essence, the escalating price structure shifts the economic risks to the back end of the contract. On the other hand, a level price structure greatly reduces long-term fuel price escalation and REC price risk and concentrates the risk in the early years of the contract where forecasts of coal and gas prices are likely more reliable and REC markets and pricing exists. Also, level pricing was believed to be more attractive to potential Green Tariff Option #3 customers since their economic analysis depends on their view of the Companies' future rates. For these reasons, the Companies focused on the level price proposals.

Comparing the 100 MW, 20-year, level priced starting in December 2021 proposals from ibV and [redacted], ibV's price was $[redacted]/MWh and [redacted] price was $[redacted]/MWh. Thus, the ibV proposal was economically the best proposal. Also, ibV had progressed its project development further than [redacted], which demonstrated a greater likelihood of project completion. For these reasons, the Companies entered contract negotiations with ibV that eventually resulted in the contract with Rhudes Creek Solar, LLC.

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Table 6 – Price Comparison for Finalist Proposals

Respondent	Nameplate Capacity (MW)	Start Year (Dec.)	Price ($/MWh) by Term	
			20 years	15 years
[redacted]				

3.4. 2020 Business Plan Update

The analysis that led to the Companies' decision to pursue a contract with ibV was based on assumptions from the Companies' 2019 Business Plan, which was developed in 2018. Because coal and natural gas price forecasts are lower in the Companies' 2020 Business Plan, the Companies evaluated ibV's proposal for a 100 MW power purchase agreement starting at the end of December 2021 ("ibV 100 MW PPA") based on these forecasts and other considerations. The following assumptions were included in this analysis.

- **Low, base, and high fuel prices.** The 2020 Business Plan fuel prices assumed in this analysis are shown in Table 7.[16] In all scenarios, fuel prices are assumed to escalate through the analysis period.
- **Zero and high CO_2 emissions prices.** The 2020 Business Plan included an assumption of zero CO_2 emissions prices. The CO_2 emissions price scenarios assumed in this analysis are shown in Table 7. The high CO_2 emissions price is based on the Synapse Energy Economics Spring 2016

[16] The low fuel price scenario was evaluated with low coal and natural gas prices, the base fuel price scenario was evaluated with base coal and natural gas prices, and the high fuel price scenario was evaluated with high coal and natural gas prices.

National Carbon Dioxide Price Forecast Low Case and is the same as the forecast used by the Companies to prepare their 2018 Integrated Resource Plan that was filed with the Commission.[17, 18]

The Companies included the high CO_2 emissions price scenarios for illustrative purposes in the absence of actual CO_2 regulations that include emissions pricing. For the high CO_2 emissions price scenarios, the analysis did not consider any changes to the composition of the generating fleet that would likely be prudent in a high CO_2 emissions price scenario. This action likely results in a more favorable evaluation of the ibV 100 MW PPA because the avoided cost in a high CO_2 emissions price scenario that includes coal unit retirements would be lower than the case without retirements. In a high CO_2 emissions price environment, natural gas-fired generation or renewables would be expected to replace retiring coal-fired units and these units would dispatch at a lower marginal energy cost compared to the Companies' marginal coal-fired generation. Therefore, the results from the high CO_2 emissions price scenario should be viewed with caution but it is not surprising that solar energy is more attractive with CO_2 pricing.

- **Four levelized REC price scenarios.** The Companies evaluated the energy cost savings of the ibV 100 MW PPA under four levelized REC price scenarios – $0/REC, $[redacted]/REC, $[redacted]/REC, and $[redacted]/REC.
- **Unit life scenarios.** In the Companies' 2020 Business Plan, existing generating units are assumed to retire when they reach 65 years of age. A scenario in which existing generating units are assumed to retire when they reach 55 years of age was also included in this analysis. In both 55- and 65-year life scenarios, retired generating units are assumed to be replaced by 1x1 NGCC units (368 MW each) as needed to maintain the Companies' minimum target reserve margin. This 55-year life scenario makes the analysis more sensitive to future natural gas price forecasts than was the case in the previous phase of the analysis.
- **No modeled change to unit commitment.** Due to the intermittent nature of renewable generation and the size of the proposals being evaluated, the Companies assumed no change to the 2020 Business Plan's modeled commitment of existing units and no need for added renewable integration costs including possible transmission system upgrades.
- **Generation profile correlated to weather.** The hourly generation forecast for the ibV 100 MW PPA was developed by ibV using weather data reflecting the Companies' 2020 Business Plan's weather assumptions.
- **No off-system sales**. Generation for off-system sales is very small compared to native load energy requirements and highly uncertain due to market factors that are out of the Companies' control. Therefore, consistent the Companies' prior practice for making resource planning decisions, the potential impact to off-system sales was not considered in the analysis.

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[17] *See* Synapse's "Spring 2016 National Carbon Dioxide Price Forecast" (March 16, 2016) at http://www.synapse-energy.com/sites/default/files/2016-Synapse-CO2-Price-Forecast-66-008.pdf. Synapse's CO_2 emissions prices were presented in real 2015 dollars and for this analysis, have been escalated to nominal dollars at 1.8% annually.
[18] *The 2018 Integrated Resource Plan of Louisville Gas and Electric Company and Kentucky Utilities Company*, Case No. 2018-00348.

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Table 7 – Fuel and CO_2 Emissions Prices

	Natural Gas Prices (2020 Business Plan Henry Hub; Nominal $/MMBtu)			Coal Prices (2020 Business Plan Illinois Basin; FOB Mine; Nominal $/MMBtu)			CO_2 Emissions Prices (Nominal $/short ton)	
	Low	Base	High	Low	Base	High	Zero	High
2020	[redacted]						-	-
2021							-	-
2022							-	-
2023							-	-
2024							-	-
2025							-	-
2026							-	17.00
2027							-	18.17
2028							-	19.37
2029							-	20.62
2030							-	21.90
2031							-	23.23
2032							-	24.59
2033							-	26.00
2034							-	27.44
2035							-	28.94
2036							-	30.47
2037							-	32.05
2038							-	33.68
2039							-	35.36
2040							-	37.09
2041							-	38.87
2042							-	46.51
2043							-	48.56
2044							-	44.52
2045							-	46.51
2046							-	48.56
2047							-	50.67
2048							-	52.84
2049							-	55.08
2050							-	57.37

Table 8 summarizes the NPVRR in 2019 dollars and levelized NPVRR for the ibV 100 MW PPA assuming zero REC prices and over a range of fuel price, CO_2 emissions price, and unit life scenarios. Negative values indicate that a proposal would be expected to lower system energy costs for customers over the

proposal's term.[19, 20] The contract is projected to have a favorable impact on revenue requirements in all high CO_2 emissions price scenarios as well as the high fuel price scenarios with zero CO_2 emissions prices. However, with zero REC prices, the contract is unfavorable in the low and base fuel price scenarios with zero CO_2 emissions prices. Lower fuel price forecasts from the 2020 Business Plan reduce the Companies' forecast of marginal energy costs and therefore the savings in energy costs associated with the ibV 100 MW PPA compared to the analysis performed using the 2019 Business Plan assumptions.

Table 8 – NPVRR for the ibV 100 MW PPA (Zero REC Prices, Negative values indicate savings and positive values indicate greater costs)

Pricing	CO_2 Emissions Price Scenario	Unit Life Scenario	NPVRR ($M; 2019 Dollars)			Levelized NPVRR ($/MWh)		
			Low Fuel	Base Fuel	High Fuel	Low Fuel	Base Fuel	High Fuel
Level	Zero	55-Year	[redacted]					
		65-Year	[redacted]					
	High	55-Year	[redacted]					
		65-Year	[redacted]					

Figure 2 shows annual nominal net revenue requirements for the ibV 100 MW PPA in the six zero CO_2 emissions price scenarios, assuming zero REC prices.[21] These charts show the year in which each scenario is expected to save energy costs without REC sales. In the High Fuel cases, the crossover year is around 2027, regardless of the unit life scenario. However, the crossover year is delayed until the early 2030s in the Base fuel scenario, again with little differences between the unit life scenarios. Not surprising, it is only in the Low fuel scenario where at the crossover year is delayed until the late 2030s or, in the 55-year Unit Life scenario, savings never occurs because system costs decrease with low natural gas prices and the replacement of coal with NGCC generation. This sensitivity to future fuel prices is why the ability to sell RECs is an important aspect of the economics of the Solar Power Contract.

[19] Because the level of Green Tariff Option #3 participation was unknown during this phase of the analysis, the NPVRR values reflect the modeled costs and benefits for 100% of the proposals' energy. With 75% of the PPA costs, RECs, and energy allocated to Green Tariff Option #3 participants and 25% allocated to all customers, the NPVRR figures could be scaled to 25% to reflect the NPVRR to all customers. Green Tariff Option #3 participation does not directionally change the economic favorability of the PPA for all customers or the levelized NPVRR values.
[20] The average annual energy cost savings for each scenario are shown in Section 6.4.
[21] Figure 2 focuses only on the zero CO_2 emissions price scenarios because the PPA's NPVRR is favorable in all high CO_2 emissions price scenarios.

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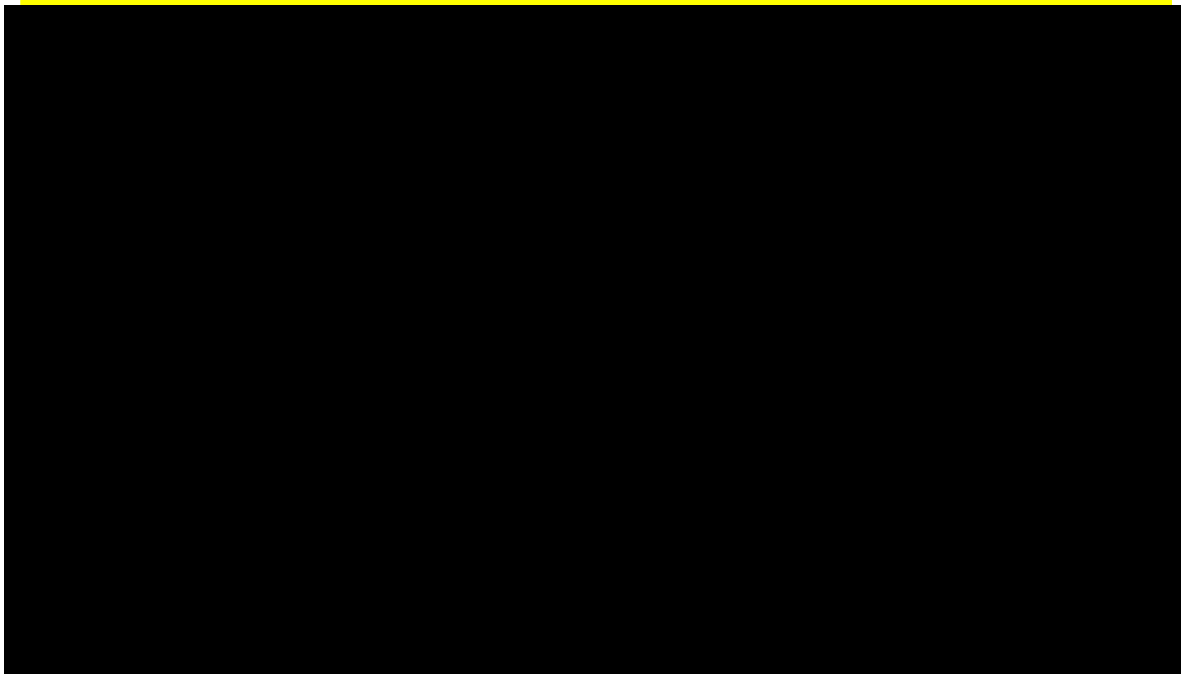
Figure 2 - Annual Nominal Net Revenue Requirements by Fuel Price Scenario, Unit Life Scenario (Level Pricing; Zero CO_2 Emissions Prices; Zero REC Prices)



3.4.1. REC Price Considerations

Because REC prices are expected to be positive in the near-term, the Companies considered the market for RECs in choosing between the level and escalating energy pricing options. REC prices are subject to the supply and demand for RECs in states with renewable energy mandates as well as changes in the laws and regulations that govern these mandates. The Companies have gained experience with selling solar RECs primarily into the Ohio market from renewable energy generated by the Brown Solar station since 2017. Figure 3 shows the prices at which the Companies have sold RECs as well as the current market prices for RECs in recent and upcoming years.[22] The current market price for 2021 RECs is $6.88/REC.

[22] The market REC prices reflect the average of the bid and ask prices for Ohio Certified Solar RECs as of October 25, 2019.

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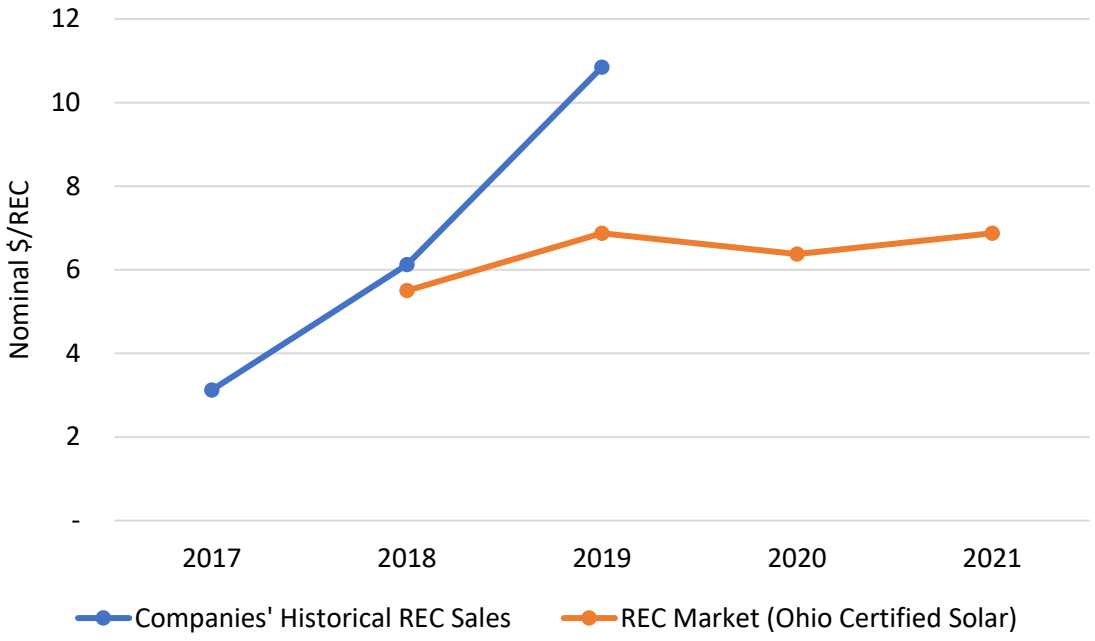
Figure 3 - Solar REC Prices ($/REC)



The Companies computed REC prices for each pricing option and for each year of the ibV 100 MW PPA that would cause the contract to have at least a neutral impact on annual revenue requirements. The analysis focused only on the twelve zero CO_2 emissions price scenarios because the contract's NPVRR is favorable in all high CO_2 emissions price scenarios. Table 9 summarizes the results of this analysis. In years where the contract already has a favorable impact on annual revenue requirements, the "breakeven" REC price is zero. While the laws regarding RECs are continually subject to change and there is no liquid market for RECs to cover the contract term, the breakeven REC prices are lower than the current market price for 2021 RECs ($6.88/REC) for both pricing options in all years for all scenarios except the last five years of the low fuel price, 55-year unit life scenario for the escalating pricing option. The breakeven REC prices range from zero to $[redacted]/REC with a level energy price and from zero to $[redacted]/REC with an escalating energy price. However, with an escalating energy price, the breakeven REC prices in the low and base fuel price scenarios are much higher in the latter half of the contract term when the market price for RECs is more uncertain. The Companies chose the level pricing option in part to mitigate the risk associated with long-term REC pricing, as discussed in Section 3.3.

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Table 9 – Breakeven REC Prices for the ibV 100 MW PPA ($/REC; Zero CO_2 Emissions Prices)

	65-Year Unit Life						55-Year Unit Life					
	Level			Escalating			Level			Escalating		
Year	Low Fuel	Base Fuel	High Fuel	Low Fuel	Base Fuel	High Fuel	Low Fuel	Base Fuel	High Fuel	Low Fuel	Base Fuel	High Fuel
2022	[redacted]											
2023	[redacted]											
2024	[redacted]											
2025	[redacted]											
2026	[redacted]											
2027	[redacted]											
2028	[redacted]											
2029	[redacted]											
2030	[redacted]											
2031	[redacted]											
2032	[redacted]											
2033	[redacted]											
2034	[redacted]											
2035	[redacted]											
2036	[redacted]											
2037	[redacted]											
2038	[redacted]											
2039	[redacted]											
2040	[redacted]											
2041	[redacted]											

3.4.2. Source of Energy Displaced by the ibV Solar Power Contract

All energy produced by the ibV 100 MW Solar Power Contract is assumed to displace energy from the Companies' coal and natural gas resources. For each of the twelve scenarios evaluated, Table 10 contains the percentage of the contract's energy that displaces coal generation; Table 11 contains total CO_2 emissions reductions. During the first half of the contract term, almost all of the displaced energy is from coal generation. This is because, among baseload units, the marginal energy cost of coal generation is generally higher than that of NGCC generation, which has a much higher efficiency. Compared to peaking units, coal generation has a greater opportunity to be displaced as some level of coal generation is online in every hour versus gas-fired peaking generation, which is only in service in limited periods of high demand. Even when gas-fired peaking generation is in service, its inherent efficiency in generating incremental energy results in a marginal energy cost advantage compared to coal, causing coal generation to be more likely to be displaced. However, as coal units are replaced by natural gas resources and as natural gas prices increase, the percentage of the contract's energy that displaces coal generation decreases and the percentage of the contract's energy that displaces natural gas generation increases.

Table 10 – Percent Energy from the ibV 100 MW Solar Power Contract that Displaces Coal Generation

Fuel	CO_2	Life	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	Total
Low	Zero	55-yr	98%	98%	97%	95%	88%	88%	84%	83%	83%	82%	75%	60%	57%	63%	49%	22%	20%	9%	6%	5%	64%
Low	Zero	65-yr	98%	99%	97%	94%	92%	90%	90%	92%	90%	91%	90%	89%	88%	85%	84%	84%	85%	78%	78%	80%	89%
Low	High	55-yr	98%	98%	97%	95%	95%	84%	81%	52%	53%	51%	28%	15%	14%	15%	7%	2%	2%	0%	0%	0%	45%
Low	High	65-yr	98%	99%	97%	94%	95%	92%	89%	83%	82%	81%	81%	79%	76%	77%	75%	60%	56%	31%	31%	22%	75%
Base	Zero	55-yr	93%	91%	91%	91%	81%	83%	80%	83%	80%	77%	77%	70%	61%	67%	45%	18%	18%	5%	4%	4%	62%
Base	Zero	65-yr	93%	91%	91%	91%	89%	87%	87%	89%	89%	88%	88%	85%	84%	82%	80%	80%	81%	74%	73%	73%	85%
Base	High	55-yr	93%	91%	91%	91%	88%	87%	86%	65%	62%	62%	45%	31%	28%	31%	19%	8%	7%	2%	1%	1%	50%
Base	High	65-yr	93%	91%	91%	91%	88%	90%	91%	91%	90%	90%	91%	91%	90%	91%	90%	87%	86%	62%	61%	48%	85%
High	Zero	55-yr	86%	86%	85%	88%	77%	77%	72%	54%	45%	42%	27%	19%	17%	16%	7%	3%	4%	0%	0%	0%	41%
High	Zero	65-yr	86%	87%	87%	86%	86%	83%	82%	85%	84%	82%	81%	80%	76%	74%	68%	61%	61%	34%	33%	28%	73%
High	High	55-yr	86%	86%	85%	88%	84%	84%	84%	83%	82%	81%	69%	56%	55%	59%	41%	20%	19%	7%	6%	5%	60%
High	High	65-yr	86%	87%	87%	86%	87%	86%	88%	92%	91%	92%	91%	91%	90%	89%	88%	88%	87%	80%	81%	77%	87%

Table 11 – CO_2 Emissions Reductions from the ibV 100 MW Solar Power Contract (Thousand Tons)

Fuel	CO_2	Life	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	Total
Low	Zero	55-yr	230	237	226	237	211	221	210	211	198	202	187	156	156	168	140	99	101	80	81	75	3,426
Low	Zero	65-yr	230	237	226	236	216	226	218	230	213	219	219	208	212	215	206	195	206	183	194	179	4,268
Low	High	55-yr	230	237	226	237	212	210	200	171	160	162	131	107	109	114	95	83	87	73	77	72	2,993
Low	High	65-yr	230	237	226	236	211	220	210	213	198	203	203	191	193	199	190	165	170	132	139	119	3,888
Base	Zero	55-yr	223	228	219	231	202	215	204	213	196	197	193	173	165	178	137	94	99	75	78	74	3,395
Base	Zero	65-yr	223	228	219	231	212	222	213	226	211	215	217	203	208	211	200	189	201	179	187	174	4,170
Base	High	55-yr	223	228	219	231	207	215	207	184	170	173	148	122	123	130	107	87	91	75	78	73	3,090
Base	High	65-yr	223	228	219	231	207	221	214	223	209	214	216	206	210	219	209	193	203	162	170	143	4,118
High	Zero	55-yr	214	220	210	227	197	207	193	169	145	146	119	101	101	103	83	73	78	67	72	67	2,789
High	Zero	65-yr	214	221	212	224	208	217	207	220	204	208	206	196	196	198	182	163	173	123	130	112	3,816
High	High	55-yr	214	220	210	227	205	215	208	210	194	199	176	149	151	161	130	95	99	77	80	75	3,297
High	High	65-yr	214	221	212	224	210	220	215	229	213	220	220	210	214	220	209	197	208	183	195	174	4,210

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4. Final Recommendation

This analysis demonstrates that the 100 MW, 20-year, level priced Solar Power Contract with Rhudes Creek Solar, LLC is most favorable for supporting interest in Green Tariff Option #3 and potentially lowering system energy costs for customers. As this analysis was being performed and after the Commission approved the Companies' application for the Green Tariff Option #3, the Companies met with industrial customers who had expressed interest in procuring renewable energy. As a result of these discussions, 75 percent of the Solar Power Contract's costs, RECs, and energy will be allocated to Green Tariff Option #3 participants and 25 percent will be allocated to all customers.

The NPVRR for the portion of the Solar Power Contract allocated to all customers (25 percent) is summarized in Table 12 for the scenarios evaluated previously as well as for four levelized REC price scenarios.[23] Over all the scenarios evaluated, the NPVRR in 2019 dollars ranges from [redacted] with an average of [redacted]. Only 6 of the 48 cases result in a slight [redacted] in NPVRR with only 2 cases [redacted] over the 20-year analysis period. In the 6 cases where the Solar Power Contract [redacted] NPVRR, the average [redacted], while in the 42 cases where NPVRR [redacted], the average [redacted] is [redacted]. Excluding the 24 high CO_2 emissions price cases, the overall average of the 24 zero CO_2 emissions price cases is [redacted]. In the 18 zero CO_2 emissions price cases that [redacted] NPVRR, the average [redacted], which compares favorably to the [redacted] in the 6 cases where NVPRR [redacted]. In the scenarios with low fuel prices and zero CO_2 emissions prices, the NPVRR is favorable when the levelized REC price is $[redacted]/REC or higher. In the scenarios with base fuel prices and zero CO_2 emissions prices, the NPVRR is favorable when the levelized REC price is [redacted] REC or higher. Both of these prices are well below the over $10/REC average price the Companies achieved in 2019 selling Brown solar RECs and the current forward market for RECs, thus indicating a relatively low risk of achieving the necessary pricing at this time.

[23] Negative NPVRR values indicate that a proposal would be expected to lower system energy costs for customers over the proposal's term.

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Table 12 – NPVRR for Portion of the ibV 100 MW Solar Power Contract Allocated to All Customers ($M; 2019 Dollars; Negative values indicate savings and positive values indicate greater costs)

Fuel Price Scenario	CO_2 Emissions Price Scenario	Unit Life Scenario	Levelized REC Price			
			$0/REC	$[redacted]/REC	$[redacted]/REC	$[redacted]/REC
Low	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
Base	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
High	Zero	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]
	High	55-Year	[redacted]	[redacted]	[redacted]	[redacted]
		65-Year	[redacted]	[redacted]	[redacted]	[redacted]

Figure 4 shows annual nominal net revenue requirements in each of the twelve scenarios, assuming zero REC prices, for the portion of the Solar Power Contract allocated to all customers. Over all the scenarios evaluated, annual net revenue requirements range from [redacted]. In the zero CO_2 emissions price scenarios (solid lines), annual net revenue requirements range from [redacted]. For reference, the Companies' annual fuel expense is approximately $800 million.

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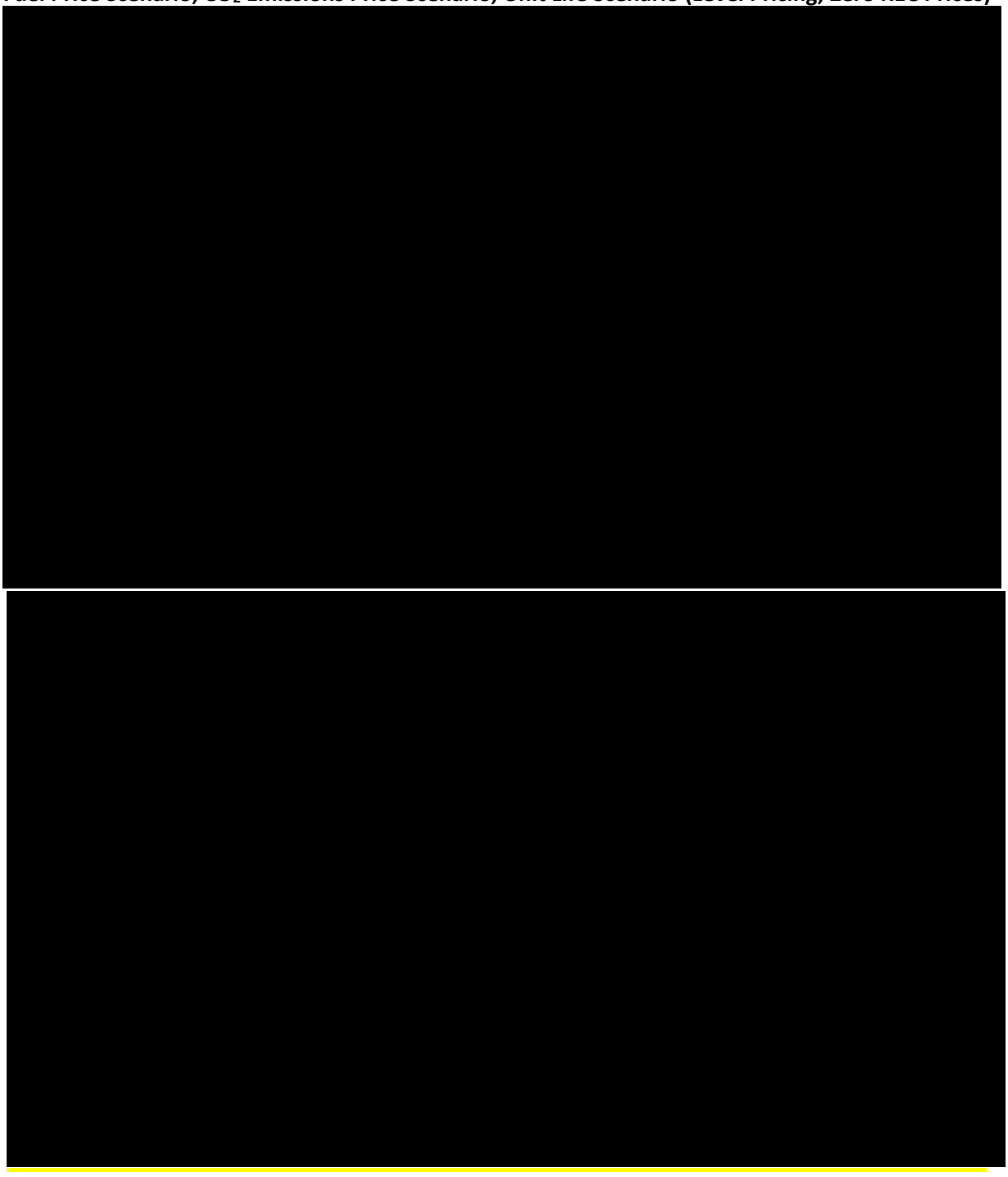
Figure 4 - Annual Nominal Net Revenue Requirements for 25 Percent Allocated to All Customers by Fuel Price Scenario, CO_2 Emissions Price Scenario, Unit Life Scenario (Level Pricing; Zero REC Prices)



As discussed in Section 3.4.1, while the laws regarding RECs are continually subject to change and there is no liquid market for RECs to cover the contract term, projected annual net revenue requirements are favorable in all years for all scenarios if the current market price for 2021 RECs ($6.88/REC) persists for the entire 20-year term. Furthermore, in the 65-year unit life scenarios, the Solar Power Contract is favorable in the base and low fuel price scenarios, respectively, if the current market price for 2021 RECs

($6.88/REC) persists through only [redacted] or [redacted] and then becomes $0/REC for the remainder of the contract term. Similarly, in the 55-year unit life scenarios, the Solar Power Contract is favorable if current market REC prices persist through [redacted] or [redacted] and then becomes $0/REC for the remainder of the contract term.

In summary, the Solar Power Contract provides the following benefits:

1. reduces future energy costs across a broad range of possible futures and provides a hedge against the risk of rising coal and natural gas prices;
2. does not result in a material increase in future energy costs should coal and natural gas prices remain relatively low over the next 20+ years;
3. almost certainly reduces energy costs with relatively modest REC pricing;
4. reduces future compliance costs should broad CO_2 regulations be implemented; and
5. provides a low-cost renewable resource to meet the needs of two large Green Tariff Option #3 customers.

Once this renewable resource is in-service, the Companies anticipate exploring additional renewable resources to further reduce system energy costs. The lessons from the Renewable RFP, the subsequent analysis, contract negotiations, and implementation will provide valuable insights for these future evaluations. In addition, this project will be the Companies' third utility-scale solar facility and one of the largest solar projects in Kentucky. It will allow the Companies to better understand the integration of a large solar facility into the existing generation and transmission systems and to further study the impact of geographical diversity on the coincident intermittence of multiple renewable resources.

5. Solar Power Contract Allocation

The Solar Power Contract energy, RECs, and associated costs will be allocated 25 percent to all LG&E and KU customers collectively and 75 percent to the two Green Tariff Option #3 participants (50 percent to Toyota and 25 percent to Dow). The Companies propose that the 25 percent allocation for all customers be assigned 39 percent to LG&E and 61 percent to KU.[24] This assignment was calculated by allocating the Solar Power Contract's forecasted generation in each hour based on each company's forecasted share of native load energy requirements for the hour. Each company's proposed assignment equals its allocated share of the total solar energy generated over the term of the Solar Power Contract. Because Toyota and Dow are KU customers, the overall allocation of the Solar Power Contract is 9.75 percent to LG&E and 90.25 percent to KU. Table 13 summarizes these allocations.

[24] This matches the existing ownership allocation of Brown Solar, for which the same allocation method was used.

Table 13 – Solar Power Contract Allocation Summary

	All Customers	Green Tariff Option #3		Overall
		Toyota	Dow	
Total Solar Power Contract Allocation	25%	50%	25%	100%
Utility Assignment				
LG&E	39%	--	--	
KU	61%	100%	100%	
Utility Allocation				
LG&E	9.75%	--	--	9.75%
KU	15.25%	50%	25%	90.25%

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6. Appendix

6.1. All Proposals Received

	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
23	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
41	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
42	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
43	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
44	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
46	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
47	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
48	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

[25] [redacted] and [redacted] updated their initial responses with new pricing. Updated prices are shown.

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	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
50										
51										
52										
53										
54										
55										
56										
57										
58										
59										
60										
61										
62										
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67										
68										
69										
70										
71										
72										
73										
74										
75										

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	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
76	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
77	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
78	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
79	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
81	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
82	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
83	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
84	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
85	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
86	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
87	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
88	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
89	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
90	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
91	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
92	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
93	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
94	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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6.2. Screening Analysis Results – All Initial Proposals

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Technology Type	Solar										

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Technology Type	Solar	[redacted]									

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Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Technology Type	Solar										
	Wind										
	Battery										
Nameplate Capacity (MW)	0-25										
	26-50										

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Nameplate Capacity (MW)	26-50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	51-75	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	76-100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Nameplate Capacity (MW)	76-100	[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]
	101-125	[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]	[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]
	126-150	[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]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	151-175	[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]
	176-200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Nameplate Capacity (MW)	176-200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Contact Term (Years)	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	12	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Contact Term (Years)	15	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Contact Term (Years)	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

Category	Group	Respondent	Location	Tech-nology	Term (Years)	Nameplate Capacity (MW)	Start Year (Dec.)	Capacity Factor	Level Price ($/MWh)	Escalating Price ($/MWh)	Price Escalation Rate
Contact Term (Years)	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Other <$30/MWh		[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]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

CONFIDENTIAL INFORMATION REDACTED

6.3. Average Annual Energy Cost Savings – Detailed Production Cost Analysis

The Companies projected hourly energy cost savings from each screened proposal in each of the natural gas price scenarios by ranking the decremental costs of each MW of each unit committed in each hour, and then summing the highest decremental costs representative of the expected renewable generation for each proposal in that hour. Dividing the sum of these decremental costs by the expected annual generation results in average annual energy cost savings. Table 14 shows average annual energy cost savings for a 100 MW solar proposal from the detailed production cost analysis using the Companies' 2019 Business Plan assumptions. The values in Table 14 were developed using the generation profile for the [redacted] proposal. This proposal was the most favorable proposal at this phase of the analysis and its generation profile is comparable to other 100 MW solar proposals.

Table 14 - Average Annual Energy Cost Savings for a 100 MW Solar Proposal by Natural Gas Price Scenario; 2019 Business Plan (Nominal $/MWh)

Gas	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Low	[redacted]																			
Base	[redacted]																			
High	[redacted]																			

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6.4. Average Annual Energy Cost Savings – 2020 Business Plan Update

Table 15 shows average annual energy cost savings for the 100 MW ibV proposal by fuel, CO_2 emissions price scenario from the Companies' 2020 Business Plan update.

Table 15 - Average Annual Energy Cost Savings for the ibV 100 MW PPA by Fuel, CO_2 Emissions Price Scenario; 2020 Business Plan (Nominal $/MWh)

Fuel	CO_2	Life	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Low	Zero	55	[redacted]																			
Low	Zero	65	[redacted]																			
Low	High	55	[redacted]																			
Low	High	65	[redacted]																			
Base	Zero	55	[redacted]																			
Base	Zero	65	[redacted]																			
Base	High	55	[redacted]																			
Base	High	65	[redacted]																			
High	Zero	55	[redacted]																			
High	Zero	65	[redacted]																			
High	High	55	[redacted]																			
High	High	65	[redacted]																			

6.5. Wind and Solar Generation Profiles

Figure 5 - Solar Hourly Mean Capacity Factor by Month

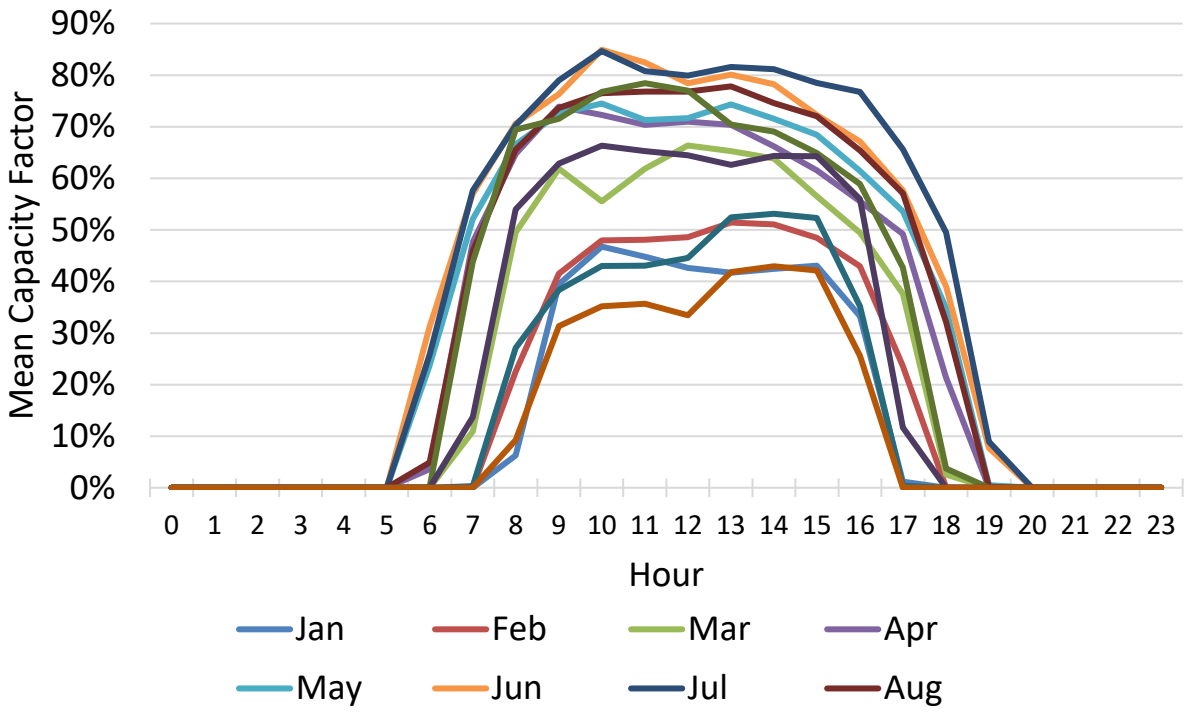


Figure 6 - Wind Hourly Mean Capacity Factor by Month

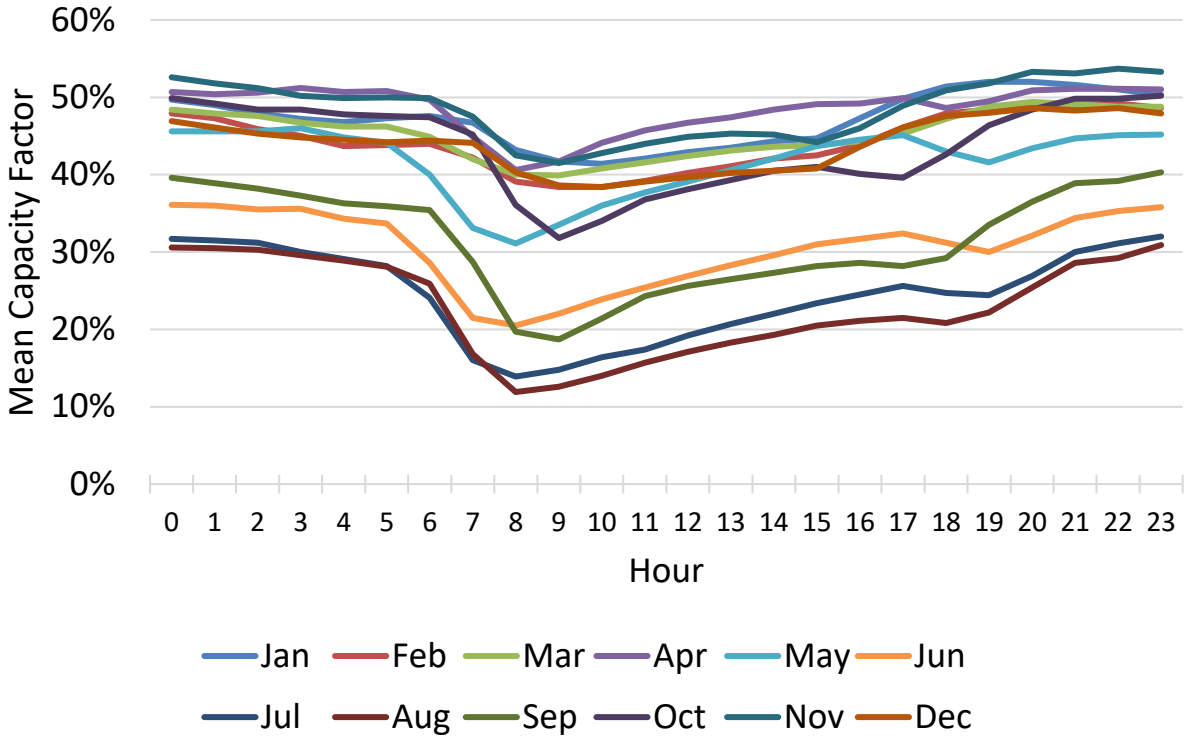
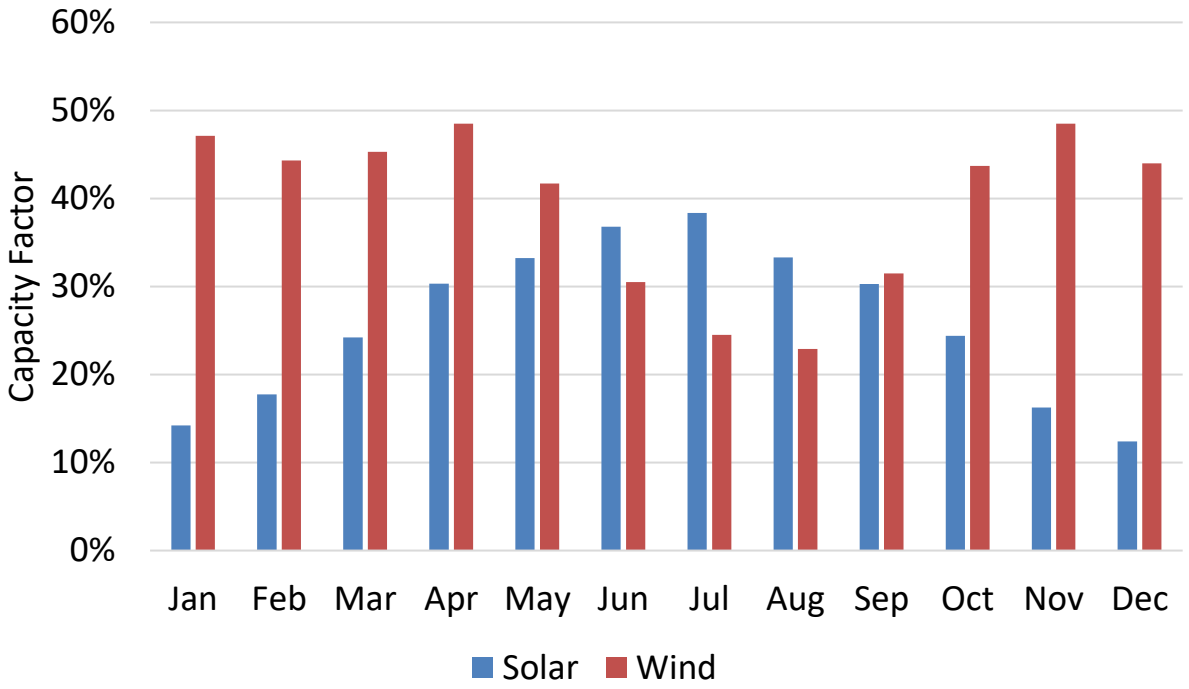


Figure 7 - Solar and Wind Capacity Factor by Month



COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF	**)**	
LOUISVILLE GAS AND ELECTRIC	**)**	
COMPANY AND KENTUCKY UTILITIES	**)**	
COMPANY FOR APPROVAL OF A SOLAR	**)**	**CASE NO. 2020-00016**
POWER CONTRACT AND TWO	**)**	
RENEWABLE POWER AGREEMENTS TO	**)**	
SATISFY CUSTOMER REQUESTS FOR A	**)**	
RENEWABLE ENERGY SOURCE UNDER	**)**	
GREEN TARIFF OPTION #3	**)**	

TESTIMONY OF
ROBERT M. CONROY
VICE PRESIDENT, STATE REGULATION AND RATES
KENTUCKY UTILITIES COMPANY AND
LOUISVILLE GAS AND ELECTRIC COMPANY

Filed: January 23, 2020

Q. Please state your name, position, and business address.

A. My name is Robert M. Conroy. I am the Vice President of State Regulation and Rates for Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") (collectively "Companies") and an employee of LG&E and KU Services Company, which provides services to KU and LG&E. My business address is 220 West Main Street, Louisville, Kentucky 40202.

Q. Please describe your educational and professional background.

A. A statement of my professional history and education is attached to this testimony as Appendix A.

Q. Have you previously testified before this Commission?

A. Yes. I have testified in numerous proceedings before the Commission. Most recently, I testified in the Companies' 2018 base rate cases and in LG&E's 2019 application for an amended gas line tracker.[1]

Q. What are the purposes of your testimony?

A. The Companies have executed an agreement ("Solar Power Contract") with Rhudes Creek Solar, LLC ("Rhudes Creek Solar") to acquire for a period of twenty (20) years the total energy output of an expected 100 MW name plate solar generation facility that will be constructed in Hardin County, Kentucky. A copy is attached as Exhibit 1 to the Application. The Solar Power Contract is subject to obtaining "all Government approvals."[2]

---

[1] *Application of Kentucky Utilities Company for an Adjustment of Its Electric Rates*, Case No. 2018-00294; *Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Rates*, Case No. 2018-00295; *Electronic Application of Louisville Gas and Electric Company for An Amended Gas Line Tracker*, Case No. 2019-00301.

[2] Power Purchase Agreement Among Rhudes Creek Solar, LLC, Louisville Gas and Electric Company and Kentucky Utilities Company, November 21, 2019, Article 18.2

In my testimony, I will first discuss why the Companies have sought Commission approval of the Solar Power Contract and then explain how the Solar Power Contract meets the legal and regulatory standards for such approval. I will also present and request the approval of the two retail Renewable Power Agreements under Option #3 of the Company's Green Tariff with two KU customers: Toyota Motor Manufacturing, Kentucky, Inc. ("Toyota") and Dow Silicones Corporation ("Dow") and discuss the ratemaking and billing issues associated with them. Both Renewable Power Agreements are directly associated with the Solar Power Contract. Copies of both contracts are found at Exhibit 2 (Toyota) and Exhibit 3 (Dow) of the Application. Finally, I will review the proposed amendment to each Company's Green Tariff to address the impact of these agreements. The proposed amendments are found at Exhibit 4 and Exhibit 5 of the Application.

Solar Power Contract

Q. Why are the Companies seeking Commission approval of the Solar Power Contract?

A. KRS 278.300(1) provides that "[n]o utility shall issue any securities or evidences of indebtedness, or assume any obligation or liability in respect to the securities or evidences of indebtedness of any other person until it has been authorized so to do by order of the commission." Past Commission precedent suggests that the Solar Power Contract is an "evidence of indebtedness" requiring prior Commission authorization.

The Commission has long held that an agreement obligating an electric utility to purchase power may constitute an evidence of indebtedness requiring prior

Commission approval. For example, in Administrative Case No. 350,[3] it noted this possibility, especially if the agreement contained a minimum payment obligation or take-or-pay provisions. The Commission subsequently determined that amendments to LG&E's and KU's wholesale power contracts constituted evidences of indebtedness requiring prior Commission approval since they obligated each Company to pay monthly minimum demand charges over the life of the contract.[4]

While the Companies have executed the Solar Power Contract, it is expressly conditioned upon the Companies obtaining all required Commission approvals on or before March 31, 2020.[5] The Companies' obligations under the Solar Power Contract will not become effective unless and until the Commission approves the Solar Power Contract.[6] The details of the Solar Power Contract are reviewed in Mr. Sinclair's testimony.

Q. What is the Commission's standard for reviewing the Solar Power Contract?

A. KRS 278.300(3) is clear that the Solar Power Contract should be approved if it is "for some lawful object within the corporate purposes of the utility, is necessary or appropriate for or consistent with the proper performance by the utility of its service to

[3] *Consideration and Determination of the Appropriateness of Implementing a Ratemaking Standard Pertaining to the Purchase of Long-Term Wholesale Power by Electric Utilities*, Adm. Case No. 350 (Ky. PSC Oct. 25, 1993) at 8-9.

[4] *Application of Kentucky Utilities Company for an Order Pursuant to KRS 278.300 and for Approval of Long-Term Purchase Contract*, Case No. 2003-00395 (Ky. PSC Dec. 30, 2004); *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. 2003-00396* (Ky. PSC Dec. 30, 2004); *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 (Ky. PSC Aug. 11, 2011*); 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 (Ky. PSC Aug. 11, 2011).

[5] *Power Purchase Agreement Among Rhudes Creek Solar, LLC, Louisville Gas and Electric Company and Kentucky Utilities Company*, November 21, 2019, Article 6.2.

[6] *Id.* at Article 6.2(A).

the public and will not impair its ability to perform that service, and is reasonably necessary and appropriate for such purpose."

In addition, where an electric utility seeks to acquire additional energy, capacity, or both through a power purchase agreement, the Commission has found that the same standard used to review the construction of generation facilities should be used to review the power purchase agreement. For example, in Case No. 2009-00545, while reviewing a proposed renewable energy purchase agreement, the Commission declared:

> Even though Kentucky Power is not now proposing to construct new generating facilities, its proposal to enter into a long-term contract to purchase such generation will have the same operational and financial implications and impacts to the utility and its ratepayers as if new generation were being constructed.
>
> Consequently, in examining the statutory criteria for approving financing under KRS 278.300(3), the "purposes and uses of the proposed issue" are for the acquisition of new generation; and for the debt to be "for some lawful object within the corporate purposes of the utility," there must be a need for additional generation and the absence of wasteful duplication.[7]

The Commission has affirmed the use of this standard of review on several occasions.[8] Recently, it rejected arguments that use of this standard was applicable only to applications for a certificate of public convenience and necessity and was inappropriate

[7] *Application of Kentucky Power Company for Approval of Renewable Energy Purchase Agreement for Wind Energy Resources Between Kentucky Power Company and FPL Illinois Wind, LLC*, Case No. 2009-00545 (Ky. PSC June 28, 2010) at 5-6.

[8] *See, e.g., Application of Kentucky Power Company for Approval of the Terms and Conditions of the Renewable Energy Purchase Agreement for Biomass Energy Resources Between the Company and ecoPower Generation-Hazard LLC; Authorization to Enter into the Agreement; Grant of Certain Declaratory Relief; and Grant of All Other Required Approvals and Relief*, Case No. 2013-00144 (Ky. PSC Oct. 10, 2013); *Electronic Application of South Kentucky Rural Electric Cooperative Corporation for Approval of Master Power Purchase and Sale Agreement and Transactions Thereunder*, Case No. 2018-00050 (Ky. PSC Sep. 27, 2018).

when a utility was merely purchasing power, not constructing any facilities.[9] In doing so, the Commission held:

> When the purpose and use of a purchase power agreement is to acquire new generation, the Commission will review the agreement pursuant to the certificate of public convenience and necessity statute, KRS 278.020. This is because entering into a long-term contract to purchase generation has the same operational and financial impact as if new generation were being constructed. Under KRS 278.020(1), a utility must establish a need for additional generation and the absence of wasteful duplication. As a result, under KRS 278.300(3), the Commission views the purpose and use of the PPA as the acquisition of new generation, and for it to be a "lawful object within the corporate purposes of the utility," there must be a need for additional generation and the absence of wasteful duplication.[10]

Q. Does the Companies' proposed purchase of power meet this standard?

A. Yes. The Companies have a clear need for renewable energy sources to meet growing customer demand for renewable energy and to meet their obligations to provide service under Green Tariff Option #3 of their Green Tariff Standard Rate Rider GT. Moreover, the non-firm economy energy purchased under the Solar Power Contract can displace higher cost fossil fuel generated energy in the course of the economic dispatch of the Companies' generation fleet and thereby provide savings to the Companies' ratepayers. As such, the energy from the Solar Power Agreement represents an efficient investment and an increased efficient use of the generation fleet.

Q. Explain the Companies' need for the generation provided through the Solar Power Contract.

[9] *Electronic Application of South Kentucky Rural Electric Cooperative Corporation for Approval of Master Power Purchase and Sale Agreement and Transactions Thereunder*, Case No. 2018-00050 (Ky. PSC Sep. 27, 2018) at 31-32.
[10] *Id.* at 6-7.

A. The Companies are experiencing increased customer interest for energy from renewable energy sources. The Companies have sought to meet this growing demand in a variety of ways, such as through their Green Tariff and Solar Share Program Riders. In their last rate cases, the Companies added the Green Tariff Standard Rate Rider GT to each of their electric tariffs to provide multiple renewable offerings.

Green Tariff Option #3 allows customers to engage with the Companies to enter into renewable energy purchase agreements to supply some or all of a customer's retail energy needs. To be eligible for Green Tariff Option #3, a customer must have a minimum monthly billing load of 10 MVA (or MW as is appropriate) and be willing to assume a contractual obligation for the electrical output from a renewable energy generator. The energy from the newly-developed renewable facility must be delivered to the Companies' transmission system. The initial term of the contract must be equivalent to the term of the agreement with the renewable energy provider, with a minimum period of five years. Green Tariff Option #3 effectively obligates the Company to seek out and acquire renewable energy for customers who meet the tariff's availability provisions and request renewable energy sources.

Both Toyota and Dow expressed an interest in renewable energy to meet their own corporate sustainability goals. Toyota has inquired about the purchase of renewable power from the Companies on several occasions in the past years. Dow expressed interest in the Green Tariff Option #3 after its approval by the Commission in April 2019. The Companies presently lack the renewable energy sources to meet this additional demand from their customers. As discussed in the testimony of Mr. Sinclair, the responses to the Renewable RFP allowed the Companies to present Toyota

and Dow with concrete proposals, including draft pricing and terms, that led to interest in pursuing individual special contracts.

Q. Does the existing availability of the Companies' non-renewable energy and capacity alter the Companies' position that the Solar Power Contract is needed?

A. No. When recently addressing the question of need for additional generation, the Commission has recognized the type of generation demanded by customers is a significant factor that should be considered. In recent decisions, it found the absence of solar facilities and growing customer demand for solar-generated electricity to be sufficient evidence of a need for such facilities. The Commission has found that the construction of a community solar facility would not result in a wasteful duplication of plant due to "customers' desire for renewable resource options."[11] Similarly, it granted a certificate of public convenience and necessity for the construction of a community solar facility after noting community interest in solar generated electricity and finding "an inadequacy of existing renewable energy service" in the region.[12]

Green Tariff Option #3 places no qualifications on the purchase of renewable sourced energy to supply customer demand except that the energy serving the demand "must be generated from a renewable resource developed on or after the Kentucky

[11] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of an Optional Solar Share Program Rider*, Case No. 2016-00274 (Ky. PSC Nov. 4, 2016) at 13.

[12] *Application of East Kentucky Power Cooperative, Inc. for Issuance of a Certificate of Public Convenience and Necessity, Approval of Certain Assumption of Evidences of Indebtedness and Establishment of a Community Solar Tariff*, Case No. 2016-00269 (Ky. PSC Nov. 22, 2016) at 12. *See also Electronic Application off Duke Energy Kentucky, Inc. For An Order Declaring The Construction of Solar Facilities Is An Ordinary Extension of Existing Systems In The Usual Course of Business*, Case No. 2017-00155 (Ky. PSC July 10, 2017) (accepting applicant's argument that construction of proposed solar facilities would not result in wasteful duplication because applicant did not currently own or operate any solar facilities, and thus the proposed facilities would not be duplicative of existing units).

Public Service Commission special contract approval date."[13] The energy to be purchased pursuant to the Solar Power Contract meets this requirement.

Q. Explain how the Solar Power Contract will not result in wasteful duplication.

A. The Commission has defined wasteful duplication as "'an excess of capacity over need' and 'an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties.'"[14] The Solar Power Contract will not produce an excess of capacity. In fact, it is not a purchase of capacity, but a purchase of non-firm, economy energy. As previously discussed, there is a clear need for this form of energy for customers.

Nor will it result in excessive investment. As discussed in Mr. Sinclair's testimony, while the renewable energy is not likely to result in lower costs in every hour of the Solar Power Contract's 20-year term, the Companies expect that the energy, combined with the sale of the associated renewable energy certificates, will reduce energy costs on a present value basis over the 20-year term, depending on commodity prices.

Q. How will the Solar Power Contract affect the Companies' rates for service?

A. The Solar Power Contract involves the purchase of non-firm, economy energy. The Companies are not acquiring an asset upon which they are seeking to earn a rate of return. The only cost component that will be recovered through customer rates is the cost of the acquired energy that is not allocated to Toyota or Dow.

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[13] Kentucky Utilities Company Tariff, P.S.C. No. 19, Original Sheet No. 69 (Effective May 1, 2019); Louisville Gas and Electric Company Tariff, P.S.C. Electric No. 12, Original Sheet No. 69 (Effective May 1, 2019).

[14] *Electronic Application of Kentucky Power Company for Certification of Public Convenience and Necessity to Construct a 161 KV Transmission Line In Perry and Leslie Counties, Kentucky and Associated Facilities*, Case No. 2017-00328 (Ky. PSC Mar. 16, 2018) at 3 (quoting *Kentucky Utilities Company v. Public Service Commission,* 252 S.W.2d 885 (Ky. 1952)).

The energy purchased under the Solar Power Contract will be treated as a purchase power expense that is recovered through the Companies' fuel adjustment clauses. When the energy acquired from the solar generation facilities displaces higher cost generation, the savings in lower energy costs will be directly and immediately passed through to the Companies' customers in the form of a reduced fuel adjustment charge on customer bills.

The proceeds from the sale of RECs for the 25% portion of the solar energy that will be allocated to native load customers will also be distributed to customers through the operation of the fuel adjustment clause just as is done currently for the sale of RECs from the Brown Solar facility.

Q. Will the energy from the PPA that is deemed delivered to Toyota and Dow impact the energy cost of all other customers?

A. Yes. By displacing energy that otherwise would have been generated, the Solar Power Contract will reduce overall fuel costs for all customers.

Renewable Power Agreements

Q. Has KU entered into two Renewable Power Agreements with Toyota and Dow?

A. Yes. These agreements are attached as Exhibit 2 and Exhibit 3 to the Application and are subject to the Commission's approval. Toyota and Dow are not parties to the Solar Power Contract, but their Renewable Power Agreements, as special contracts, were developed consistent with the Companies' rights and obligations under the Solar Power Contract. Section 1 in the Renewable Power Agreements describes the commitment of the customers to the same 20-year term, beginning at the commercial operations date, and price of the Solar Power Contract. The testimony of Mr. Sinclair reviews the other provisions in the Renewable Power Agreements.

Q. How will the customers be billed under their Renewable Power Agreements?

A. The billing under the Renewable Power Agreement will be added to each customer's monthly billing. Each customer will be billed using the rates from the applicable tariff schedule (e.g., Time-of-Day Primary Service) and the Renewable Power Agreement. In addition, the customer will pay a renewable energy charge per kWh for all allocated renewable energy. Each kWh of allocated renewable energy in a 15-minute interval is offset against a kWh of the customer's energy usage so that the customer is not subjected to two energy charges for the same kWh used. To the extent the allocated renewable energy is coincident with the customer's energy usage during the 15-minute interval, the customer's peak and intermediate demands will be reduced by the amount of allocated renewable energy delivered in the respective 15-minute interval. The customer's base demand will not be adjusted for coincidence with the renewable energy as the base demand charge represents cost associated with the transmission and distribution system that continues to serve the customers.

The customer will also receive a bill credit for all allocated renewable energy in excess of the customer's energy usage in the 15-minute interval. The credit will be calculated as KU or LG&E's avoided energy cost based on the applicable company LQF tariff rider. Sections 2.7 and 2.8 of the Renewable Power Agreements contain the specific details. This approach generally is consistent with the methodology used in and approved for the Companies' Solar Share program.[15]

Q. How will the energy acquired under the Solar Power Contract be allocated between the Companies?

[15] *Electronic Joint Application of Kentucky Utilities Company and Louisville Gas and Electric Company for Approval of an Optional Solar Share Program Rider*, Case No. 2016-00274 (Ky. PSC Nov. 4, 2016).

A. For each interval of time (e.g., an hour), the energy received from the Solar Power Contract will be allocated as follows: 50 percent to Toyota, 25 percent to Dow, and 25 percent to all customers. Furthermore, for the 25 percent that is allocated to all customers, 39 percent is allocated to LG&E customers and 61 percent is allocated to KU customers. In other words, LG&E customers will receive 9.75 percent and KU customers will receive 15.25 percent of the energy in an hour of the 25 percent that is not allocated to Toyota and Dow. The Companies determined the 39/61 percentage share using the conventions in the Companies' Power Supply System Agreement. The allocation is the same as the existing ownership allocation of the Companies' Brown Solar Generating Station.

Proposed Amendment to Green Tariff

Q. Are the Companies proposing to amend the Green Tariff Standard Rate Rider GT ("Green Tariff")?

A. Yes, each Company is proposing to slightly modify its Green Tariff. The Application and the proposed tariff sheets attached to the Application reflect the minor amendment to increase the system cumulative MW name plate AC from 50 to 125 MW in Green Tariff Option #3.

Q. Why is the Green Tariff being amended?

A. Currently, Green Tariff Option #3 for both Companies caps the cumulative output at 50 MW. The proposed 125 MW allows for the introduction of other renewable sources in the future, should customers request more renewable power and the Companies issue another Renewable RFP. The Companies believe that the potential of an aggregated 250 MW should be absorbable in the Companies' system without material integration issues.

Q. What are your conclusions and recommendations?

A. I recommend the Commission approve the Solar Power Contract, the two Renewable Power Agreements and the proposed amendment to each Company's Green Tariff Option #3.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says he is the Vice President of State Regulation and Rates for Kentucky Utilities Company and Louisville Gas and Electric Company, he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge, and belief.

ROBERT M. CONROY

Subscribed and sworn to before me, a Notary Public in and before said County and State this 21st day of January 2020.

(SEAL)

Notary Public, State at Large

Notary Commission No. 603967

My Commission Expires:

7/11/2022

APPENDIX A

Robert M. Conroy
Vice President, State Regulation and Rates
Kentucky Utilities Company
Louisville Gas and Electric Company
220 West Main Street
Louisville, Kentucky 40202
Telephone: (502) 627-3324

Previous Positions

Director, Rates	Feb 2008 – Feb 2016
Manager, Rates	April 2004 – Feb 2008
Manager, Generation Systems Planning	Feb. 2001 – April 2004
Group Leader, Generation Systems Planning	Feb. 2000 – Feb. 2001
Lead Planning Engineer	Oct. 1999 – Feb. 2000
Consulting System Planning Analyst	April 1996 – Oct. 1999
System Planning Analyst III & IV	Oct. 1992 - April 1996
System Planning Analyst II	Jan. 1991 - Oct. 1992
Electrical Engineer II	Jun. 1990 - Jan. 1991
Electrical Engineer I	Jun. 1987 - Jun. 1990

Professional/Trade Memberships

Registered Professional Engineer in Kentucky, 1995
Edison Electric Institute - Rates and Regulatory Affairs Committee
Southeastern Energy Exchange - Rates and Regulation Committee

Education

Essentials of Leadership, London Business School, 2004
Masters of Business Administration
Indiana University (Southeast campus), December 1998
Center for Creative Leadership, Foundations in Leadership program, 1998.
Bachelor of Science in Electrical Engineering;
Rose Hulman Institute of Technology, May 1987

Civic Activities

Olmstead Parks Conservancy – Board of Directors – 2016 – current
Leadership Kentucky – Class of 2016
Financial Research Institute – Advisory Board Member – 2016 – current