Southern Renewable Energy Association
P.O. Box 14858, Haltom City, TX 76117
SouthernRenewable.org

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PUBLIC SERVICE COMMISSION

January 17, 2020

Gwen R. Pinson
Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

RE: LOUISVILLE GAS AND ELECTRIC AND KENTUCKY UTILITIES INTEGRATED RESOURCE PLAN
DOCKET #2018-00348

Dear Ms. Pinson,

This letter constitutes the Readlst file required by 807 KAR 5:001, Section 8(5).

The Southern Renewable Energy Association has not requested intervention in Louisville Gas & Electric and Kentucky Utilities' Integrated Resource Plan (Docket #2018-00348); however, pursuant to 807 KAR 5:001, Section 11(2e), we file the attached written comments regarding the subject matter of the case, including an original unbound and ten (10) additional copies.

Sincerely,

Simon Mahan

Simon Mahan
Executive Director
Southern Renewable Energy Association
simon@southernwind.org
337-303-3723

cc: Service List, Electronically

Southern Renewable Energy Association

P.O. Box 14858, Haltom City, TX 76117

LOUISVILLE GAS AND ELECTRIC AND KENTUCKY UTILITIES (LGE&KU)

2018 INTEGRATED RESOURCE PLAN

DOCKET #2018-00348

COMMENTS OF THE SOUTHERN RENEWABLE ENERGY ASSOCIATION

January 17, 2020

The Southern Renewable Energy Association (SREA) is an industry-led initiative that promotes the use and development of renewable energy in the south. Since 2013, SREA has engaged in integrated resource plan (IRP) processes in Arkansas, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, Tennessee and Virginia. We strive to provide the most up-to-date publicly available market information regarding renewable energy resource availability, pricing, performance and forecasting. SREA appreciates the opportunity to comment on the Louisville Gas and Electric and Kentucky Utilities (LGE&KU) 2018 IRP.

LGE&KU is the largest utility in Kentucky with a generation peak of over 7,000 MWs and approximately 8,200 MWs of generation capacity. Some 63% of LGE&KU's generation capacity is coal-fired generation (5,156 MW), with natural gas combustion and steam turbines making up an additional 28% (2,259 MW), and a natural gas combined cycled facility representing another 8% (662 MW). Peak demand forecasts are expected to reach approximately 6,300 MW's for the foreseeable future, with the summer and winter peaks nearly converging. Load requirements are expected to remain flat at approximately 32,500 GWh annually for the foreseeable future. Nearly 80% of electricity generated by LGE&KU is from coal-fired power plants.[1]

LGE&KU anticipates very little change over the next few years based on its IRP results. Nearly 272 MW of coal units (Brown 1 and 2) and an additional 14 MW of natural gas (Zorn 1) are slated for retirement in the near-term. Between 2023-2026, LGE&KU's IRP identifies several units that will reach a 55-year operating life and may retire SCCT's (49 MW in 2023), Haefling 1-2 (24 MW in 2025), Brown 3 (415 MW in 2026), and Mill Creek 1 (299 MW in 2027). In 2029-2033, LGE&KU may retire Ghent 1 and Mill Creek 2 (770 MW in 2029), Ghent 2 (481 MW in 2032, and Mill Creek 3 (390 MW in 2033). In the 55-year age base scenario, LGE&KU would add 5 1x1 NGCC's, with 300 MW solar; however, it is unclear when those procurements would take place. But, "Aside from the planned retirements of Brown 1, Brown 2, and Zorn 1, no changes or additions to the Companies' generation resources are planned for the next three years." LGE&KU also states, "Absent further retirements, the Companies do not have a need for capacity through the 15-year planning period."

Table 5-15: Long-Term Resource Plans

Generating Unit Life	Load Scenario	Gas Price	Zero CO_2 Price	High CO_2 Price
55-Year	Base	Base	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 400 MW Solar
		High	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 500 MW Solar
		Low	5 1x1 NGCCs, 300 MW Solar	5 1x1 NGCCs, 300 MW Solar
	High	Base	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 100 MW Solar
		High	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 500 MW Solar
		Low	7 1x1 NGCCs, 100 MW Solar	7 1x1 NGCCs, 200 MW Solar
	Low	Base	4 1x1 NGCCs	4 1x1 NGCCs, 300 MW Solar
		High	4 1x1 NGCCs	4 1x1 NGCCs, 500 MW Solar
		Low	4 1x1 NGCCs	4 1x1 NGCCs
65-Year	Base	Base	No additional changes	No additional changes
		High	No additional changes	No additional changes
		Low	No additional changes	No additional changes
	High	Base	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
		High	1 1x1 NGCC, 100 MW Batteries	1 1x1 NGCC, 300 MW Solar, 300 MW Wind
		Low	1 1x1 NGCC, 100 MW Batteries	2 1x1 NGCC, 400 MW Solar
	Low	Base	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		High	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs
		Low	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs	Retire Small-Frame SCCTs, DCP, Brown 3 or Brown 11N2 SCCTs

Source: LGE&KU 2018 IRP[2]

Review of LGE&KU's Renewable Energy Assumptions

LGE&KU's IRP uses the National Renewable Energy Lab's Annual Technology Baseline (NREL ATB) data for generation technology cost and performance assumptions. The company's Brown Solar facility achieved approximately 20% capacity factor in 2017, which matches closely the NREL ATB data used for the IRP. The company also evaluated in-state wind energy and out-of-state wind energy imports, plus the cost of transmission. Given the low cost of renewable energy resources, especially given several existing higher-cost generation units in LGE&KU's fleet, it is surprising that the IRP does not include at least some level of renewable energy procurement in the near-term. SREA is quite familiar with IRPs, and in this sort of situation, two primary problems typically arise. First, utility IRP methodologies include inherent additive costs that unnecessarily and artificially increase renewable energy cost assumptions. Second, IRP software may overly depend on capacity-only additions. Both problems appear with LGE&KU's IRP, albeit to what extent is unclear.

SREA applauds LGE&KU for selecting the NREL ATB data regarding renewable energy resources. NREL's ATB data is industry standard and reflects recent market offerings for renewable energy resources. For example, NREL's 2019 ATB (published in August 2019, after LGE&KU filed this IRP) shows wind energy resources for a levelized cost of energy (LCOE) of $30-$50/MWh, and utility-scale solar resources for a similar price.[3] These values do not include the federal production tax credit (PTC) for wind energy, nor the federal investment tax credit (ITC) for solar energy, which would decrease these costs further.

Table 2: Generation and Demand-Side Resource Options

Type	Category	Technology Option	Summer Capacity[10] MW	Contribution to Peak[11] Summer	Contribution to Peak[11] Winter	Net CF %	Heat Rate[12] MMBtu/MWh	Capital Cost[12] $/kW	Fixed O&M[12] $/kW-yr	Firm Gas Cost[13] $/kW-yr	Variable O&M[12] $/MWh	Fuel Cost $/MWh	Trans. Cost $/MWh
Generation Resources (2018 Dollars)	Peaking	SCCT	201	100%	100%	5-90	9.8	911	13	22	7.31	27.90	N/A
		Battery Storage	1-500	100%	100%	5-40	N/A	2,073	9	N/A	2.72	N/A	N/A
	Baseload / Intermediate	NGCC	368	100%	100%	10-90	6.4	1,070	11	19	2.83	18.36	N/A
		Supercritical Coal	500	100%	100%	50-90	8.8	3,757	34	N/A	4.86	17.51	N/A
		IGCC	500	100%	100%	50-90	8.6	4,028	56	N/A	7.84	17.13	N/A
		Coal w/30% CO_2 Capture	500	100%	100%	50-90	9.7	5,202	72	N/A	7.31	19.33	N/A
		Coal w/90% CO_2 Capture	500	100%	100%	50-90	11.5	5,752	84	N/A	9.88	22.82	N/A
		Nuclear	1,000	100%	100%	70-90	10.5	5,884	103	N/A	2.36	6.92	N/A
		Biopower (Dedicated)	50	100%	100%	50-90	13.5	3,948	114	N/A	5.69	41.02	N/A
		Biopower (Co-fire)	500	100%	100%	50-90	9.7	4,068	34	N/A	4.86	54.79	N/A
	Renewables	KY Wind	50-500	15%	33%	30-40	N/A	1,637	53	N/A	N/A	N/A	N/A
		Non-KY Wind	50-500	15%	33%	40-50	N/A	1,515	53	N/A	N/A	N/A	12
		PV Solar	1-500	80%	0%	18-22	N/A	1,093	10	N/A	N/A	N/A	N/A
		Hydro	10-100	60%	40%	20-40	N/A	5,826	32	N/A	N/A	N/A	N/A
DSM	Demand-Side	DCP[14]	127	100%	0%	N/A	N/A	N/A	18	N/A	$5/ customer	N/A	N/A

LGE&KU did not publish the LCOEs of the various generation technologies, making it difficult to ascertain if there are inherent additive costs that increase renewable energy cost assumptions; however, LGE&KU did provide information that suggests this is the case: LGE&KU stated that, "Assuming a 37% capacity factor, the levelized cost of the Kentucky wind option is approximately $61/MWh." A wind energy resource with a 37% capacity factor would be a mid-level Techno-Resource Group (TRG) 6 (TRG-6) type resource in the NREL ATB. As published by NREL, a TRG6 resource results in an LCOE of $37/MWh in 2020, or about 40% lower than stated in the IRP. LGE&KU also included a 48% capacity factor wind resource to represent wind energy imports; the company states, "Assuming a 48% capacity factor, the levelized cost of the out of state wind option is approximately $57/MWh, including additional costs for transmission." However, the company adds $12/MWh for additional transmission costs (without explanation or justification of this value), to arrive at a cost of $57/MWh; suggesting a base-price of $45/MWh. A 48% capacity factor resource is a TRG1 in NREL's ATB, and NREL's LCOE for a TRG1 wind energy resource is just $28/MWh. Again, LGE&KU's LCOE for the highest quality wind energy resource appears to be roughly 40% higher than NREL's ATB. Increasing costs by 40% for wind energy or solar energy resources would potentially cause the total exclusion of wind energy or solar energy resources in IRP modeling. LGE&KU did not publish a similar narrative regarding solar energy resources; however, SREA strongly suspects that the same variables artificially inflating the cost of wind energy resources are likely inflating solar energy and energy storage resource cost assumptions, too.

SREA recommends benchmarking IRP model LCOE's for renewable energy resources against given LCOE's from NREL's ATB as well as publicly available data from requests for proposals (RFPs) or actual power purchase agreement (PPA) contracts. By comparing IRP model LCOEs against external values, internalized variables can be pin-pointed as artificially increasing cost estimates. For example, in other IRP proceedings, SREA has found that a utility's internal cost assumptions regarding asset ownership can drastically increase the costs of renewable energy resources. Internal utility assumptions regarding self-ownership of new renewable energy generation assets tends to double-count financing costs. These are problems inherent in model assumptions that are unknowable without comparison with LCOEs, and without direct comparison of all variables included in model making. For renewable energy resources, LCOE's provide good benchmark comparisons for potential real-world PPAs, and virtually all utilities SREA has interacted with report some level of LCOE's in IRP processes.

It is unclear how LGE&KU treats market-based energy purchases in its models. The company states that in "ELDCM, the scarcity price is specified as a single value and is approximately $55/MWh. Because the scarcity price is difficult to specify, the analysis considered scarcity price sensitivities." This seems as if market purchases would be disallowed if available for less than self-generation, but not until prices hit $55/MWh. Also, if wind energy prices are set at $57/MWh, but scarcity prices are accepted at $55/MWh, it is unclear that wind energy resources would ever be selected instead of scarcity prices. Some clarification regarding how LGE&KU treats possible market-based purchases would be helpful.

Xcel Energy RFP Results are Lower than LGE&KU's Data Assumptions

Xcel Energy, a Colorado electric utility, published the results of its 2017 All-Source Solicitation request for proposals in December 2017.[4] Xcel received over 400 bids representing over 100,000 MW of capacity from a wide variety of technologies; however, most bids provided wind energy or solar power resources. The median bid price or equivalent for stand-alone wind energy resources was $18.10/MWh, suggesting several projects below and above that price. Adding battery storage to wind energy resulted in median bids of $21/MWh. For stand-alone solar energy resources, the median bid was $29.50/MWh. Adding battery storage to solar energy resulted in median prices of $36/MWh. While these prices may be specific to Xcel, the fact remains that these represent real project bids and are aligned with other projections and these comments. Again, because Xcel evaluated PPAs, the values presented below are in $/MWh format, which is similar to an LCOE figure. LGE&KU should publish LCOE values for its generation technology assumptions to make it easier to compare the real-world PPAs against its assumed resource costs.

Xcel RFP Responses by Technology 2017

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Source: Xcel Energy 2017[5]

NIPSCO RFP Results are Lower than LGE&KU's Data Assumptions

Northern Indiana Public Service Company (NIPSCO), an electric company in the MISO system, held an integrated resource plan (IRP) meeting on July 24, 2018 to discuss renewable energy options. As part of its

IRP process, NIPSCO shared results from an all source request for proposals (RFP) summary. NIPSCO received bids for wind energy, solar energy, energy storage, and amalgamations of those resources together. The company received proposals across five states, predominately via power purchase agreement (PPA), but also as asset sale or option. Resources offered as asset sale or as an option were provided at an average bid cost of $1,151.01/kW for solar energy projects, and $1,457.07/kW for wind energy projects. For PPAs, average bids for solar energy reached $35.67/MWh, and average bids for wind energy reached $26.97/MWh. Solar-plus-energy storage projects were offered as asset sales at $1,182.79/kW and as a PPA at $5.90/kW-Mo plus $35/MWh.[6] These values provide recent market data that are relevant to states in MISO and further south. Subsequently, NIPSCO's IRP recommended[7]:

- By 2023, the IRP preferred plan calls for adding approximately 1,150 MW of solar and solar+ storage, 160 MW of wind, 125 MW of DSM and 50 MW of market purchases to the NIPSCO supply portfolio
- Retire all of NIPSCO's coal capacity by the end of 2028

NIPSCO RFP Responses by Technology 2018

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	90	20,585	59	13,247			

Source: NIPSCO 2018[8]

NIPSCO's data shows that LGE&KU's cost assumptions for wind energy are approximately 40% higher than resources bid into Northern Indiana's RFP last year. A 40% higher cost associated with wind energy or solar energy resources would potentially cause the total exclusion of wind energy or solar energy resources in IRP modeling.

SWEPCO's IRP Assumptions are Lower than LGE&KU's Data Assumptions

The Southwestern Electric Power Company (SWEPCO), with customers in Arkansas, Louisiana, and Texas, recently completed its IRP in Arkansas.[9] SWEPCO modeled wind energy resources, stating "The resource had a LCOE of $21.85/MWh in 2021 with an 80% PTC, without congestion and losses. The levelized congestion and losses for the 2021 wind resource is estimated to be approximately $6/MWh." SWEPCO also modeled utility-scale solar, stating "Initial costs for Tier 1 were approximately $1,180/kW in 2021 with the ITC. Tier 2 has an initial cost of approximately $1,310/kW in 2021 with the ITC."

SWEPCO's Preferred Portfolio:

- "Adds utility-scale solar resources in 2025 through 2032, for a total of 1,300MW (nameplate) of utility-scale solar by the end of the planning period."
- "Adds 600MW (nameplate) of wind resources in 2022 and 2023 and 200MW (nameplate) in 2024, with additional wind resources added through 2029, for a total of 2,000MW (nameplate) by the end of the planning period."

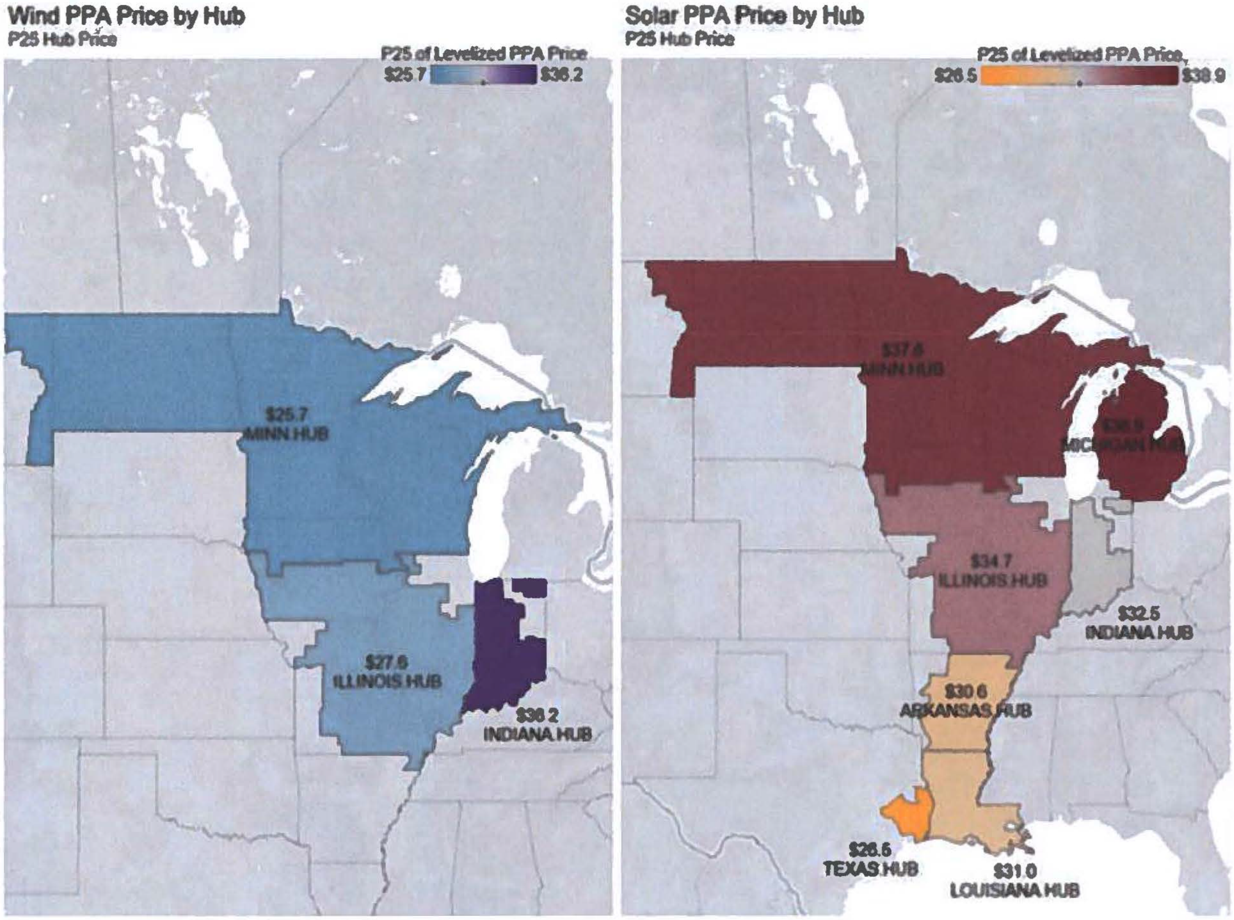
Cleco's IRP Assumptions are Lower than LGE&KU's Data Assumptions

Cleco Power LLC, an electric utility in Louisiana, recently published its Draft IRP. Cleco found that "The preferred portfolio includes acquiring up to 400 MW of installed solar capacity, as well as up to 1,000 MW of installed wind capacity."

- Cleco evaluated wind energy with a PPA. Cleco states, "The wind PPA assumed a fixed price of $20/Mwh over the term of the study with an additional $7/MWh adder for potential firm transmission costs, whether incurred by congestion costs between MISO North and South or for wheeling out of SPP. Due to the increased prevalence and strength of wind as a resource in certain geographic areas in TRG 1 areas relative to MISO South, a higher capacity factor of 48%-53% will be used for the wind PPA." These prices are in line with SWEPCO's IRP, NIPSCO's RFP and NREL's ATB.
- Cleco also evaluated solar energy with a PPA. Cleco states, "The solar PPA will use a fixed price of $35/MWh over the term of the study. Since it is assumed to be in MISO South, no transmission adder or capacity factor adjustment will be made relative to the self-build option." These prices are in line with SWEPCO's IRP, NIPSCO's RFP and NREL's ATB.

Additional Utility Benchmarks

Several other publicly available data points exist for recent renewable energy PPAs. For example, the Georgia Power 2019 IRP has stated that the company's average solar power purchase agreement reached $36/MWh in 2017.[10] In North Carolina, competitive procurement of solar energy resources recently led to an average price of $31.24/MWh per proposal.[11] In Lafayette, Lafayette Utilities System (LUS) recent wind energy PPA for 50 megawatts (MW) is currently providing energy for $31.86/MWh and is providing nearly 20% of Lafayette's energy.[12] LevelTen Energy, and independent aggregator of renewable energy buyers and sellers, releases quarterly information regarding renewable energy PPA's by region. Recent wind energy PPA prices in the MISO North area range from $25.7/MWh-$36.2/MWh and solar energy PPA prices range from $32.5/MWh-$38.9/MWh.[13]



Source: LevelTen 2019[14]

SREA recommends that LGE&KU publish LCOEs for its generation technology assumptions, and that those costs be adjusted to reflect publicly available data from NREL's ATB, NIPSCO, Xcel, and other utilities.

Federal Tax Credits Were Not Properly Evaluated

The federal Production Tax Credit (PTC) and Investment Tax Credit (ITC) are the primary incentives for the wind energy industry and solar energy industry, respectively. Because of congressional action in 2015, the PTC and ITC are being phased out, even while federal incentives for conventional forms of generation remain in place. The information provided below is meant to provide additional clarity regarding the PTC and ITC and generally how these incentives should be considered for modeling purposes. It is not apparent that LGE&KU's IRP even includes the PTC or ITC.

Production Tax Credit

Wind energy developers can qualify projects for specific PTC rates by commencing construction in a particular year and bringing such projects online within four calendar years. For example, a wind energy project that commences construction by the end of 2016 has until the end of 2020 to begin operation, and still qualify for the full PTC. Projects that begin construction in 2017 have until the end of 2021 to become operational and qualify for a 20% reduced PTC value; 2018 projects can come online by 2022 and 2019 projects by 2023 with further 20% annual reductions in PTC value. Renewable energy project developers frequently safe-harbor qualified clean energy equipment in anticipation of a future contract and reflect cost reductions in the proposals.

The PTC is awarded on a generation basis at a rate of $24/MWh for the first ten years of a project's operation. Because the PTC is a tax credit and it frequently exceeds a project developer's total tax base, developers will frequently monetize the PTC with tax equity. Tax equity erodes the full dollar value of the PTC. According to the Lawrence Berkeley National Lab (LBNL), for a developer with tax appetite, the 100% PTC value is reduced to $19.8/MWh.[15] According to LBNL, developers should expect a $15-$19/MWh reduction in overall cost of energy from the PTC. To achieve an equivalent PTC cost reduction, it is recommended that wind energy resources' overnight capital costs be reduced by roughly $600/kW for resources that become operational in 2020 (reflecting 100% of the PTC value), $500/kW for wind resources operational in 2021 (80% of PTC value), and $400/kW for wind resources operational in 2022 (60% of PTC value). Due to a last-minute Congressional extension of the wind energy PTC, the 60% PTC value has been extended by an additional year.

<u>Schedule of Wind PTC Cost Reductions by Project In-Service Dates</u>

	2019	2020	2021	2022	2023	Future
Wind PTC	$19.8/MWh	$19.8/MWh	$16.9/MWh	$14.2/MWh	$14.2/MWh	0
OR Wind PTC (Overnight $/kW translated)	*$600/kW*	*$600/kW*	*$500/kW*	*$400/kW*	*$400/kW*	*0*

Source: Adaptation from LBNL 2014[16]

<u>Investment Tax Credit</u>

Rules for the solar ITC are slightly different compared to the wind PTC. Based on IRS Notice 2018-59, "As modified, § 48 phases down the ITC [from 30%] for solar energy property the construction of which begins after December 31, 2019, and before January 1, 2022, and further limits the amount of the § 48 credit available for solar energy property that is not placed in service before January 1, 2024." In effect, the ITC phase-out for solar ends for projects that commence construction in 2019, 2020 or 2021 by January 1, 2024. For solar projects that begin construction on or after January 1, 2022, a permanent 10% ITC is available.[17]

Most utility-scale solar energy projects will elect to receive the ITC, which is based on total project expenditure. It is recommended that the full 30% ITC be incorporated for projects that begin operation before 2024, and a 10% ITC be incorporated for projects that begin operation in 2024 and future years. Additionally, new energy storage projects can also qualify for the ITC, provided that those projects are added to new or existing wind energy or solar energy projects. Currently, stand-alone energy storage projects do not qualify for the federal ITC.[18]

Schedule of Solar ITC Cost Reductions by Project In-Service Dates

Construction Begins	2019 Operational	2020 Operational	2021 Operational	2022 Operational	2023 Operational	Future Op.
Before 2020	30%	30%	30%	30%	30%	10%
2020		26%	26%	26%	26%	10%
2021			22%	22%	22%	10%
2022 and Future				10%	10%	10%

Source: Adaptation from IRS 2018[19]

Hybrid Renewable and Energy Storage Systems Need Evaluating

LGE&KU states that "CO2 prices also weaken the overall value of battery storage, as the energy arbitrage value from off-peak coal-fired generation is eroded." LGE&KU did not explain if the company evaluated renewable energy resources in conjunction with energy storage devices. These so-called "hybrid" resources have significantly higher capacity values and can perform additional ancillary services. Because energy storage devices would be charged by renewable energy resources, LGE&KU's statement, that off-peak coal-fired generation costs increase due to CO2 pricing schemes, suggests hybrid systems were not evaluated.

Capacity Planning is Deficient

SREA's concern with capacity-based planning is that that even if renewable energy cost assumptions were below avoided cost, a utility's modeling methodology would refuse to select low-cost renewable energy, regardless of price. This has been proven true with other IRPs. When asked in various Entergy IRP proceedings if their capacity-based modeling would select a hypothetical $0/MWh renewable energy resource if no capacity need existed, Entergy staff indicated that the models would not select such a resource without a capacity need. Capacity-only planning leads to a Catch-22 for renewable energy resources. In instances where capacity needs are satisfactorily met under the status quo, a model will not select new low-cost energy resources and instead rely on higher cost capacity resources for energy delivery. However, when a capacity-based model is provided a capacity need (either through extensive retirements or significant load growth), renewable energy resources are only evaluated on their capacity value, not their low-cost energy contributions. Capacity-only planning leads to over-building of new natural gas power plants, when a mixture of low-cost renewable energy resources would likely lead to overall reduced ratepayer costs. To be clear, this is not an argument that all existing capacity resources should be retired. In a normal dispatch, higher cost generation resources would be ramped down to accommodate lower cost renewable energy resources when available. Lower-cost energy-based resources reduce actual costs; however, capacity-only planning does not take the normal dispatch operations into consideration. This is an unfair standard that always leads to devaluing renewable energy resources, while always building rate-based new natural gas power generation.

Synapse Energy Economics has noted the deficiency of capacity expansion models, stating:

> "In addition, some capacity expansion models are unable to endogenously retire EGUs, and require these decisions to be made outside of the model construct. While making decisions outside the

model reduces computational requirements, it may introduce user error or bias. For example, a modeler may not review economic retirements, and thus fail to capture a cost- effective compliance mechanism."[20]

According to Moody's Investors Service, "Some coal plants still perform economically, but competitiveness could come under pressure as market conditions evolve...Most municipal- or G&T-owned coal plants in the US are old and have high production costs. According to the report, 72.3% of these plants, or about 65.0 gigawatts, have operating costs exceeding $30 per megawatt hour, which Moody's views as the threshold above which coal plants are vulnerable to be displaced by cheaper generation options. Newer units that came online after 2000 use more efficient technology and run at lower heat rates and operating costs, enabling many of them to be competitive with the market and achieve higher capacity factors. Others are located adjacent to coal mines, allowing them to eliminate transportation costs from their overall fuel expenses. Nonetheless, each plant's competitiveness will ultimately depend on external factors including the price of natural gas and renewable energy in the vicinity, regional transmission organization reserve margins and the extent of political support for various fuels."[21] As Moody's points out, broader energy market forces will render higher cost energy resources (such as existing steam turbine generation) obsolete and likely to be out-competed by lower cost energy resources such as renewable resources.

The self-reported FERC Form 1 data from LGE&KU shows that the company owns, operates, or purchases a substantial amount of energy at over $35 per megawatt hour ($35/MWh). At that price, both wind energy and solar energy resources are available at lower prices and should have been selected in a truly ***integrated*** resource plan. As shown by LGE&KU, wind energy and solar energy resources do provide some additional capacity value when added to the system, which would positively affect the company's reserve margin and LOLE.

Over-reliance on capacity-focused modeling underestimates renewable energy benefits while retaining older, less efficient generation. Taken to the extreme, a capacity-only planning process could lead to unusual model results that recommend significant power generation development or legacy generation retention that are rarely used, at the expense of low-cost energy options. This outcome appears to have occurred, given that low-cost wind energy and solar energy generation were not selected in the next few years. Capacity-focused planning does not initially address economic costs; alternatively, an energy-based financial dispatch model would efficiently dispatch necessary resources. LGE&KU should evaluate energy planning options, not just capacity.

Review of LGE&KU Portfolios

LGE&KU ran a number of generation portfolio simulations and provided some data on a few of those runs. One of the least-cost options is to retire Brown 3 (See IRP Table 13). The largest cost savings from that portfolio comes from entirely eliminating a capacity cost (Column A) of potentially more than $30 million annually.

Brown 3's coal-fired average heat rate is anticipated to remain around 12,100 BTU/kWh (IRP Table 8-5) and run at roughly 20% capacity factor (IRP Table 8-3) into the foreseeable future. The marginal resource cost for Brown 3 is provided as $84/MWh in 2021 dollars (IRP Table 9). LGE&KU states that, "With Brown 3 in the generation portfolio, the portfolio is far more reliable and reliability and generation production costs are significantly less volatile." It should be obvious that retaining generation retains reliability, and retaining a well-known expensive generator diminishes volatility. However, reliability can be provided with new generation technologies, and price volatility of a low-cost resource is not inherently worse than a stable-higher cost resource. Knowing that a generation unit is anticipated to cost a stable $84/MWh in perpetuity is not in the best interest of ratepayers. While true the Generation Portfolio Scenario that includes the removal of Brown 3 (along with retirement of DCP and small-frame SCCT's) would result in a 14.2% reserve margin, with an LOLE of 7.4 (See IRP Table 13), an adequate IRP software program should be able to dynamically resolve the reserve margin and LOLE values.

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

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

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

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

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

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

Brown 5-11's are peaking units and marginal resource costs are provided at $79/MWh (IRP Table 9), with anticipated capacity factors in the 0-11% range for individual units into the foreseeable future. Alternatively, Scenarios retiring Brown Units 8, 8-9, or 8-10, or 8-11 result in very little annual capacity cost savings, but elevated reliability and generation production costs; it appears entirely possible that in those scenarios where those peaking units are eliminated, the scenario models select more power generation from Brown Unit 3. Because Brown Unit 3 is a higher-cost resource in LGE&KU's fleet, increasing its usage would necessarily inflate overall generation costs. Whether the models are either voluntarily or forcibly selecting higher cost energy to make up for shortfalls from the Brown Units 8-11 retirements is unknown at this point. To determine if that's the case, the IRP Table 8-3 for capacity factors should be published for all scenarios.

Table 9: Marginal Resource Costs (2021 Dollars)

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

In 2018, LGE&KU reported that the EW Brown facility generated over 2 billion kilowatt hours (kWh), or over 2,000 gigawatt hours (GWh) for roughly $96 million, at a rate of $47/MWh. Also in 2018, the Paddy Run, Brown CT and Trimble CT units contributed nearly 1.6 billion kWh's (1,592 GWh), at a total cost of $96 million, or an average rate of roughly $60/MWh. Approximately 2 GW of utility-scale solar power (at 20% capacity factor), or roughly 1 GW of utility-scale wind power (at 40% capacity factor), would supply an equivalent amount of energy provided by EW Brown, Paddy Run, Brown CT and Trimble CT combined (or 3,600 GWh annually). Solar power and wind power are readily available in the LGE&KU region at roughly $30-$35/MWh, or potentially below those prices. LGE&KU ratepayers could be overpaying for power by $64 million to $82 million annually. As provided earlier in Table 9, LGE&KU's Stay-Open Costs and Average Energy costs for EW Brown, Brown 5-11, Paddy's Run, and Trimble County are above the costs reported in the company's FERC Form 1 data, suggesting the $64 million to $82 million estimated annual loses are conservative.

LGE&KU FERC Form 1 Data (2018)

	EW Brown	Ghent	Haefling	Cane Run	Trimble	Paddy's Run	Brown	Trimble
Type	Steam	Steam	CT	CC	Steam	CT	CT	CT
Constructed	1957	1973	1970	2015	2011	2001	1994	2002
Last Installed	1971	1984	1970	2015	2011	2001	2001	2004
Capacity (MW)	757.16	2226.06	41.4	630.24	509.9	83.75	781.43	783.67
Net Gen (MWh)	2,035,354	11,264,692	(159)	3,674,673	2,730,794	37,798	344,113	662,767
Total Cost	$1,142,114,177	$3,088,389,929	$4,384,886	$427,933,220	$910,596,080	$39,812,228	$292,721,678	$254,008,143
$/kW Capacity	$1,508	$1,387	$ 106	$679	$1,789	$475	$375	$324
Production	$1,764,410	$3,802,306		$1,144,079	$1,477,716	$ -	$178,088	$8,735
Fuel	$63,690,984	$238,903,831	$134,451	$81,869,704	$53,698,322	$2,832,218	$15,592,229	$39,881,563
$/kWh	$0.0470	$0.0296	$(1.1751)	$ 0.0249	$0.0267	$0.0836	$0.0526	$0.0624
Capacity Factor	31%	58%	0%	67%	61%	5%	5%	10%

Source: Kentucky Utilities Company 2019[22]

	Mill Creek	Zorn	Cane Run	Cane Run	Trimble	Paddy's Run	Brown	Trimble
Type	Steam	CT	CT	CC	Steam	CT	CT	CT
Constructed	1972	1969	1968	2015	1990	1968	1999	2002
Last Installed	1982	1969	1968	2015	2011	2001	2001	2004
Capacity (MW)	1717.2	18	16.32	117.76	543.99	143.09	199.87	408.73
Net Gen (MWh)	8,639,800	(73)	32	1,036,446	3,212,603	42,338	160,119	344,884
Total Cost	$2,140,361,732	$1,974,689	$3,726,356	$122,997,318	$874,033,785	$51,504,570	$76,327,993	$132,047,975
$/kW Capacity	$1,246	$110	$228	$692	$1,607	$360	$382	$323
Production	$3,270,732	$ -	$ -	$322,689	$1,578,643	$ -	$44,633	$4,567
Fuel	$187,391,364	$ 13	$336,313	$23,091,452	$67,023,391	$4,226,718	$6,579,914	$20,621,805
$/kWh	$0.0299	$(0.6421)	$14.5112	$0.0249	$0.0277	$0.1130	$0.0456	$0.0619
Capacity Factor	57%	0%	0%	100%	67%	3%	9%	10%

Source: Louisville Gas and Electric Company 2019[23]

LGE&KU IRP Recommendations

- LGE&KU should move away from capacity-only or capacity-focused resource planning.
- LGE&KU should allow renewable energy to directly compete against existing generation units.
- The National Renewable Energy Lab's Annual Technology Baseline should be used for all renewable energy resource cost and performance assumptions.
- Energy storage resources should be allowed to access multiple revenue streams including but not limited to frequency control, voltage regulation, energy arbitrage, peaking and other value stacks.
- Cost projections for renewable energy and energy storage should continually decline over time, while performance projections should continually increase.
- Federal tax credits, including the PTC and ITC, should be incorporated for renewable energy and energy storage projects in relevant years, as provided in these comments.
- Levelized cost of energy benchmarks (in $/MWh values) should be provided for all energy resources. LCOE values should be like Lazard Associates' and NREL ATB values.
- Significant procurement of renewable energy and energy storage should occur across all portfolios.
- Large customers should be allowed to directly procure renewable energy resources.

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