COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR CERTIFICATES 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	)	Case No. 2014-00002

PUBLIC COMMENTS OF BIG RIVERS ELECTRIC CORPORATION

Comes Big Rivers Electric Corporation ("*Big Rivers*"), through counsel, and submits the following comments on the joint application that Louisville Gas and Electric Company ("*LG&E*") and Kentucky Utilities Company ("*KU*") (together, the "Applicants") filed in this proceeding.

These comments are limited because Big Rivers does not know and cannot require the Applicants to disclose the reasons why they rejected Big Rivers' generating resources as solutions to either their short-term or long-term needs for energy and capacity and because Big Rivers does not have the information or underlying data necessary to evaluate the Applicants' analysis of the Big Rivers options or to evaluate the Applicants' analysis of the selected option of constructing a new natural gas-fired generating plant (the "*Green River NGCC*"). In light of these limitations, Big Rivers requests only that the Kentucky Public Service Commission (the "*Commission*") ensure that the Applicants fairly evaluated the option of constructing the Green River NGCC, that the Applicants' analyses of the new construction and the alternatives were based on sound, reasonable, and consistent assumptions, that the Applicants' choice to construct the Green River NGCC is not a detriment to the Applicants' ratepayers and the Commonwealth, that the Green River NGCC and related transmission projects are not wasteful duplications of facilities, and that the construction of the Green River NGCC is otherwise consistent with the laws and policies of the Commonwealth. More specific concerns are addressed in the following sections.

A. Features of the Phase 2 and 3 analyses bear closer examination

The Phase 2 analysis consisted of comparing select resources identified in Phase 1 to self-build resources "to determine the best resource for meeting the Companies' long-term capacity and energy needs." Exhibit DSS-1 explained that "[w]hen considering a new resource, it must be evaluated in the context of the Companies' generation portfolio and transmission system to understand the alternative's impact on:

- system production costs,
- resource expansion plans, and
- transmission system expansion plans."

The analysis calculated a 30-year present value revenue requirement ("*PVRR*") for each resource under 12 "analysis scenarios" (summarized in Table 9 of Exhibit DSS-1) combining alternative forecasts for load growth, natural gas prices, and CO_2 prices. Importantly, Exhibit DSS-1 further explained that "[t]o focus the analysis on finding the best resource for serving the Companies' native load and eliminate the need to speculate on future power prices, the analysis assumed the Companies had no access to energy from the market and made no off-system sales."

There are features of the Phase 2 and Phase 3 analyses that bear closer examination, including:

1. Are the assumptions used in the Phase 2 and Phase 3 analyses reasonable and consistently applied to all options?
2. Why did the Applicants' exclude off-system sales opportunities from their analyses? At best, this treatment is unrealistic and thus likely to result in distorted outcomes. This approach may have introduced a systematic bias that penalizes coal resources. By assuming such sales will not occur, the Applicants disfavor coal-fired power in many scenarios. By assuming that sales will never occur in the future, the Applicants have ignored the value that low-cost baseload coal would bring in terms of opportunities to sell to third parties and reduce ratepayer costs. During low load hours when the Applicants might have excess capacity, coal-fired capacity (especially Big Rivers' low-cost capacity) might be saleable for a profit, while power from a Green River NGCC is much less likely to be economic. For example, under mid or high case natural gas prices, a Green River NGCC would have a variable cost well above coal-fired power. Thus, off-system sales opportunities would be greater with a coal-fired purchase power agreement ("*PPA*"), and at least some of the profits from those sales would accrue to ratepayers.
3. Did the Applicants factor the costs of addressing the shortfall in capacity in 2016-2018 into the PVRR of the Green River NGCC? Is it reasonable for the Applicants to select an option that does not address the capacity shortfall in 2016-2018 and to reject Big Rivers' proposals that would address that shortfall?
4. Are the CO_2 prices assumed in Table 8 of Exhibit DSS-1 (starting at $23/ton in 2020 rising to $119/ton by 2042) reasonable? They appear too high for "base" expectations, and should have been assigned a lower probability than 50% for several reasons, such as:

a. The Synapse "Mid" case (which is the basis for the "Mid" CO_2 price scenario) does not include utilities that assigned zero CO_2 price in their reference cases. For example, Entergy's 2012 resource plan[1] assumed zero CO_2 price in the reference case, but this observation was not included in the dataset that Synapse used to construct the "Mid" case. In addition, it is not clear whether all the utility resource plans included in the Synapse study assigned a probability as high as 50% for the prices assumed in their "Mid" cases.

b. Under the current projections for gas prices, a \$23/ton starting CO_2 price in 2020 would likely result in rapid switching from coal to other resources. Such an abrupt retirement of many coal units could reasonably be expected to raise system reliability risks and create political push-back. For example, under the "Mid" gas price of \$5.39/MMBtu and coal price of \$2.57/MMBtu in 2020 (see Table 7 of Exhibit DSS-1), a very efficient coal unit at 10,000 btu/kWh heat rate would have higher dispatch costs than a gas unit operating at 7,000 btu/kWh heat rate. In addition, low or negative margins for coal units at that CO_2 price would not allow full recovery of annual fixed costs of operations and maintenance (typically at more than \$30/kW-year for existing units), and would increase the likelihood of early retirement for a substantial portion of the coal generation fleet in the region.

5. Why did the Applicants assign equal probabilities to the scenarios as to varying assumptions about natural gas and CO_2 prices? There are fundamental inconsistencies between the Applicants' scenario definitions and assigned probabilities. The Applicants' approach incorporates three uncertain factors in their analysis: (1) natural gas prices

[1] http://www.entergy-neworleans.com/content/IRP/2012_IRP.pdf, page 22.

(three levels), (2) carbon policy (two alternatives: Zero and mid), and (3) load growth (two paths) that they group into scenarios. There are 12 scenarios consisting of combinations of each uncertain variable. The Applicants assume that the three natural gas price levels are each equally likely (probability 0.333), the two carbon policies are considered equally likely (probability 0.5), and that the low load path occurs with probability 0.2 and the mid path probability 0.8. With these underlying probabilities, there are six scenarios involving mid load with the same weight in the expected PVRR (0.133 probability each), and six scenarios involving low load with the same weight in the expected PVRR (0.033 probability each). See Table 9 of Exhibit DSS-1 for a summary of scenario probabilities.

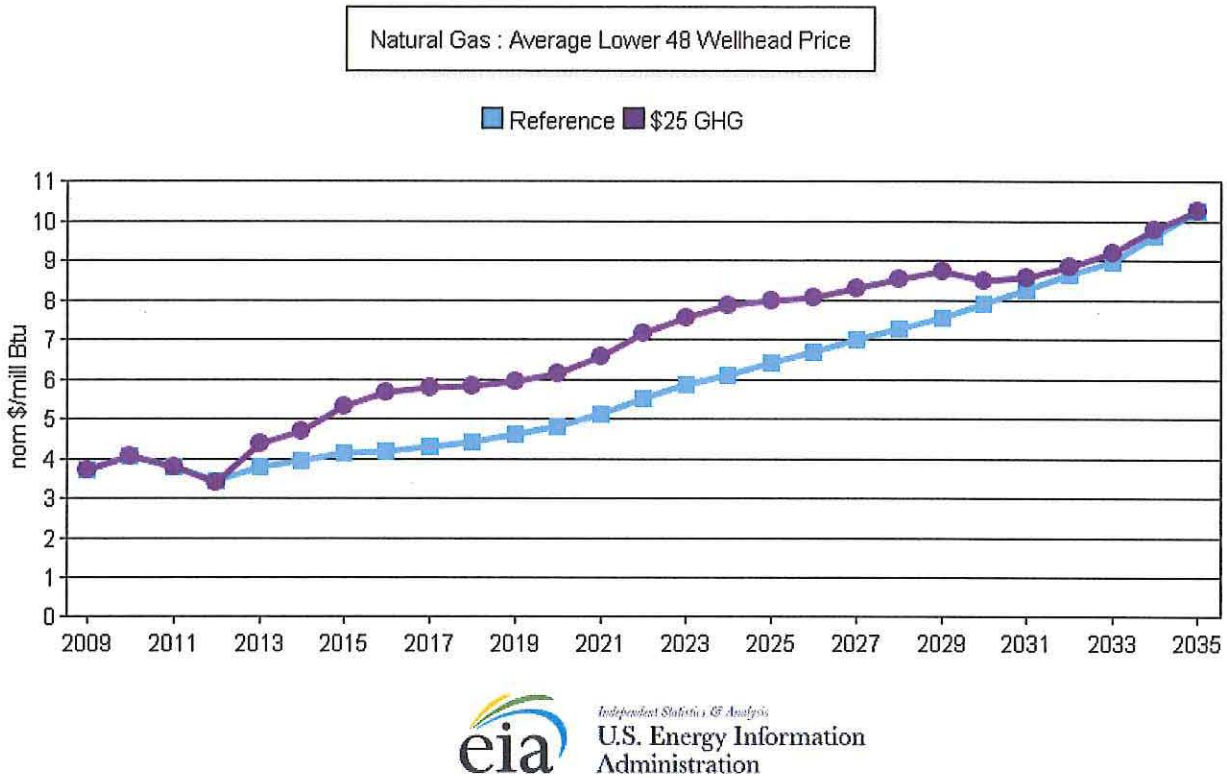
The flaw with the Applicants' method for weighting scenarios is that, given a load growth path, each of the scenarios is, in reality, not equally likely. For example, it is not clear why a coincidence of mid CO_2 and mid to low gas prices, which would tend to penalize coal resources, should be assigned the same probability as a coincidence of high CO_2 and high gas prices (the likelier result of high CO_2 prices).

This can be illustrated logically by considering the impact of increasing CO_2 costs. The carbon policy assumed by the Applicants starts at \$23/ton in 2020 and rises to \$119/ton by 2042. This type of policy would add about \$20/MWh to the dispatch price of coal in 2020 and only about \$8/MWh to the dispatch price of gas combined cycle ("*CC*"). This effect on CC capacity factors is shown in the Applicants' response to Item 34 of the Commission Staff's First Information Request. The response shows that, under all scenarios, the mid carbon policy results in capacity factors above 90% starting in 2020. The reason for this is that with the carbon price included in dispatch, the CC is less expensive on a dispatch basis than coal. This pattern of coal vs. gas competition would be replicated in most regions of the country, and this would result in a large increase in natural gas demand, which would lead to an increase in natural gas prices. Thus, natural gas prices at the low level paired with mid carbon is much less likely than natural gas prices at the mid or high levels paired with mid carbon.

The Applicants could have used EIA Annual Energy Outlook 2012 cases to make appropriate and approximate adjustments to the natural gas prices or guided a more meaningful set of scenario probabilities. As noted by David Sinclair in the Applicants' response to Item 56 of the Attorney General's First Information Request, the Applicant's state that they are relying on EIA data:

> The Low, Mid, and High prices at the Henry Hub are annual average prices based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2012. The EIA forecast is a publicly available long-term projection of natural gas prices. The "Mid," "High," and "Low" case natural gas price forecasts are based on EIA's AEO 2012 "Reference," "Low Estimated Ultimate Recovery" ("high" price), and "High Technically Recoverable Resource" ("low" price) cases, respectively, **which provides internally consistent alternative views of the path of development of the resource base**. (Emphasis added)

The effect of a carbon policy on reference case natural gas prices is estimated by EIA for several carbon price levels. As indicated in the graphic below, EIA carbon price scenarios are expected to correspond to higher natural gas prices. The price effect is due to increased natural gas demand under the carbon policy. Had the Applicants adjusted the probabilities (or the natural gas prices themselves) for this basic relationship, the Green River NGCC would have been a less favorable option.



6. What is the impact of the PPA risk factor attributed to imputed debt? The joint application describes an additional cost attributable to PPAs in section 4.1.5.2: PPA Financing Costs. Additionally, in response to Item 126 of the Attorney General's First Information Request ("*AG 1-126*"), the Applicants provide a sample calculation illustrating the referenced imputed debt adjustment used for PPAs. While it is not clear exactly what incremental impact the PPA financing cost had on the evaluation of Big Rivers' proposals, based on section 4.1.5.2 of the joint application and the sample calculation, the cost calculation should be examined and qualified, if necessary, in the following respects:

   a. The sample calculation overstates the impact of the imputed debt adjustment needed to preserve the target debt ratio indicated in the example. This is because the example includes only the cost of additional equity needed to rebalance the company's capitalization in recognition of imputed debt, but not the corresponding reduction in actual debt. This can be seen in Exhibit A, which is attached hereto, and which is adapted from the Applicants' response to AG 1-126.

- *The Applicants' Calculation.* Based on the Applicants' original assumptions on lines 1-8 of page 1 of the attachment to the response to AG 1-126, the Applicants' calculation is reproduced and disaggregated into key components on lines 15-23 of Exhibit A hereto. The calculation in Exhibit A begins by deriving the imputed debt represented by capacity payments of $10 per kW-year for a 500MW plant over a 20-year contract period. The present value of remaining capacity payments is discounted at an assumed long term borrowing cost of 3.75% (line 16) and multiplied by a stipulated risk factor of 50% (line 17) to drive the imputed debt amount (line 18), which is $34.7 million for 2016 in this example. Then, as a first step toward preserving a target debt ratio of 45.7%, $18.9 million ($34.7 million x 54.3%) of additional equity is assumed to be added to the company's capital structure (line 20). The annual revenue requirement associated with this incremental equity is $18.9 million multiplied by a target return of 10.50% (line 21) and grossed up for taxes at a rate of 38.90% (line 22) to result in $3.2 million for 2016 (line 23).
- *The Missing Debt Calculation.* What the Applicants' calculation fails to account for is that the company's debt ratio inclusive of the imputed debt will exceed the target ratio of 45.7% unless the additional equity is applied to reduce overall debt. This will result in a corresponding reduction to the

revenue requirement calculated above equal to $18.9 million multiplied by the assumed long term borrowing cost of 3.75%, or $0.71 million in 2016 (line 28 of Exhibit A hereto). The resulting incremental debt ratio is shown on lines 31-36: ($34.7 million - $18.9 million)/$34.7 million = 45.7%. The net incremental revenue requirement of $2.5 million for 2016 is shown on line 38.[2]

b. The imputed debt cost described above can reasonably be expected to be small under a short-term PPA for a base load unit. Notably, the present value of remaining capacity payments described above would be reduced by approximately 2/3 under a 5 year term vs. the 20 year term assumed. Further, the imputed debt cost, based on capacity payments, should be significantly diluted in $/MWh terms by the high capacity factors appropriate to assume for a baseload plant (please see the table of the Big Rivers Coal Units' capacity factors on page 15).

c. A 50% risk factor should not necessarily apply in calculating debt equivalency for a Big Rivers PPA. The joint application suggests that "regulators use a utility's rate case to establish base rates that provide for the recovery of the fixed costs created by PPAs," and hence that a 50% risk factor would be applied by rating agencies to calculate debt equivalency for any PPA. It is true that that the Fuel Adjustment Clause ("*FAC*") defined in the Kentucky Administrative Regulations limits the recovery of purchased power costs not recovered in base rates to

[2] Note that the same incremental revenue requirement could be obtained by assuming no adjustment to preserve the target debt ratio, but instead compensating equity at a higher rate of return for the increased risk of greater leverage.

"energy purchases, exclusive of capacity or demand charges."[3] This would correspond to a 50% risk factor under customary rating agency practice.[4] However, the Commission has departed from this guideline in its recent order granting Kentucky Power the right to recover all costs of a Renewable Energy Purchase Agreement ("*REPA*") with a new biomass generating resource, including capacity charges.[5] This allows for the application of a 25% risk factor instead of 50%.[6] While this order was made in recognition of a 2013 statute authorizing this treatment for biomass projects (KRS 278.271), the Commission order also recognized that "the cost of the proposed REPA would not have withstood scrutiny based strictly on a least-cost analysis." Accordingly, capacity charges under a Big Rivers PPA, subject to a finding that it provided a least-cost solution and other benefits as discussed above, may also be recoverable under a FAC. In such a circumstance, the risk factor would be 25%. With a risk factor of 25% and under a 5-year PPA, but otherwise under the assumptions posited by the Applicants in their response to AG 1-126, the incremental cost impact of imputed debt would be a fraction of that suggested by the Applicants' example, as shown in Exhibit B, which is attached hereto.

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[3] 807 KAR 5:056.

[4] The rating agency that has most fully developed debt equivalency methodologies for PPAs is Standard and Poor's ("*S&P*").

[5] Order dated January 17, 2014, in *In the Matter of: 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.

[6] S&P has a well-established practice of applying a risk factor of 25% in regulatory regimes where there are established power cost adjustment mechanisms (or lower, if costs are recovered pursuant to legislative mandate). Notably, a 25% risk factor was assumed in filings of Kentucky Power and Kentucky Industrial Utility Customers, Inc. ("*KIUC*") in connection with Case No. 2013-00144.

7. How was the 50% risk factor derived for calculating the imputed debt associated with PPA offers?

B. The Applicants draw the wrong conclusions about the value of deferring the Green River NGCC decision

The Phase 3 analysis ("Enhancements and Deferral Considerations") considers options for delaying the addition of a Green River NGCC beyond 2018. The Applicants found that under one short-term PPA option, deferring a Green River NGCC decision makes economic sense. Of particular note is Exhibit DSS-1, page 35:

> On average over all scenarios, the **[REDACTED]** (alternative C55D) cost-effectively defers the Green River 2x1 NGCC unit to 2020; this alternative reduces the weighted average PVRR of building in 2018 by **[REDACTED]** million.

The Applicants rejected this short-term PPA alternative (C55D) on non-economic grounds. However, on Exhibit DSS-1, page 41 the Applicants go on to say that other short-term alternatives would be economic in the *majority* of the scenarios:

> If the Companies knew that gas prices were going to be at or above the Mid gas price scenario, deferring the Green River unit would be least-cost. However, because there is no basis for weighting one gas price scenario more heavily than another scenario, deferring the Green River 2x1 NGCC unit is not least-cost.

This statement means that the Applicants found that except under low natural gas prices, deferral is in the best interest of the ratepayers. Since the Applicants give equal weighting to each natural gas price scenario (probability 0.333), the probability that gas prices are mid or high (and that deferral is preferable) is 67%. The Applicants ignore their own analysis and insist that proceeding with a Green River NGCC now is in the best interest of ratepayers.

C. Deferring the Green River NGCC has additional ratepayer value that the Applicants do not consider

As just observed, the Applicants' analysis shows that with a high probability, deferral is in the ratepayers' interest. On that basis alone, deferral is warranted. But the Applicants should have gone further and considered the added benefit of waiting to learn more information about the three key uncertain factors identified by the Applicants: load growth, natural gas prices and carbon policy. Uncertainty in each in each of these very important factors will be reduced over the next few years.

1. Load growth uncertainty supports deferring the Green River NGCC

The Applicants place a 0.2 probability on the low load scenario and a 0.8 probability on the mid load scenario based on a statistical analysis of the distribution of load around the 2013 load forecast. (*See* Exhibit DSS-1, page 11, n. 11.) The underlying probability distribution likely reflects only factors such as uncertainty in population, economic growth and weather.[7] The loss of a significant group of municipal customers is not considered in the load forecast. From the response to Item 1-1 of KIUC's First Information Request, the 12 cities that comprise the KU municipal load could leave the Applicants' system on three or five years notice. These cities have issues with their current LG&E/KU rates, which issues they have brought to FERC for resolution.

Loss of this load would substantially lower the Applicants' total load and likely defer their need for new generation for many years. The table provided in the Applicants' Response to KIUC 1-1(h) shows that if these customers were to leave the system in 2019, there would be a short-term capacity need (2015-2018), but then no need again until after 2020. This observation

[7] *See* Attachment 21 to the Applicants' Response to Item 1 of the Attorney General's First Information Request ("Sales to transmission municipal customers were modeled as a function of weather, the number of households, incomes and prices in the counties where the...municipal customers are located, and monthly binaries").

would support a decision to use a short-term PPA to supply the short-term need, and delay the Green River NGCC decision, which, as noted above, can be done cost effectively.

2. Natural gas price uncertainty supports deferring the Green River NGCC

Natural gas prices have been low in recent years due to large new supplies from shale resources, and (at least for a while) very soft demand during the recession. No one can predict future natural gas prices with precision, but over the next few years, we will learn more about the future supply-demand balance and, hence, the likely range of gas prices. Key factors that we will learn more about are:

- The nature of the shale reserve and the cost of development;
- Environmental mitigation that may be required, which could drive up costs (ground water contamination and methane emissions);
- The level of exports, which could drive up prices (new LNG export terminals); and
- New domestic demand in the electric and industrial sectors.

With greater knowledge about these factors in the near future, the range of uncertainty in future natural gas prices will narrow.

3. Carbon policy uncertainty supports deferring the Green River NGCC

David Sinclair (on pages 24-25 of his direct testimony) summarizes the current carbon policy situation very well:

> As I said, the future remains highly uncertain regarding CO_2 regulation in the U.S. Many people believe that the Clean Air Act is not really suited for regulating CO_2 emissions and that new legislation is needed from Congress. Given the current climate in Washington, it is hard to envision bipartisan support for GHG legislation. Second, court challenges continue related to past actions taken by EPA to regulate CO_2 emissions and threats of future litigation are being made should EPA press ahead on regulations for existing power stations. In this environment, much remains unknown about if, when, and how CO_2 might be regulated in the future.

What Mr. Sinclair does not note is that at least some of the uncertainty could be reduced by June 2014 when EPA must propose draft rules for existing generating units that would become final a year later. There are a wide range of rules that EPA could propose, from power plant efficiency standards that might have little impact on the coal fleet, to requiring carbon capture and sequestration at some point in the future.

D. Aspects of the Applicants' analysis of the Big Rivers options and the Green River NGCC bear closer examination

There are aspects of how the Applicants evaluated the Big Rivers options against the Green River NGCC that bear closer examination, which include:

1. How did the Applicants evaluate Big Rivers' PPA given that in Table 12 of Exhibit DSS-1, the only coal options shown are a 5- and 10-year term?
2. What capital and operating cost parameters did the Applicants' use in their analysis of the Green River NGCC (including capital amortization, capacity factor, outage rate, etc.) for all components of the Green River NGCC project (including the contemplated 20-inch natural gas pipeline and required transmission upgrades)?
3. Did the Applicants include in the PVRR of the Green River NGCC all financing costs for the Green River NGCC project (including the contemplated new gas pipeline and the contemplated transmission upgrades)?
4. Were the assumptions related to the cost of natural gas and the expected cost of delivery of the natural gas to the Green River NGCC plant reasonable and included in the PVRR of the Green River NGCC? Did the natural gas price projections the Applicants relied upon in their analysis incorporate the impact of CO_2 regulation on new and existing

generating sources? Did those natural gas price projections incorporate the impact of potential or existing natural gas production fracking regulations?

5. Are the assumptions used in determining the costs of the Big Rivers proposals and the costs of the Green River NGCC reasonable and consistent?
6. Did the Applicants analyze Big Rivers' current and future financial condition, and if so, were the assumptions used in that analysis reasonable?
7. Did the Applicants analyze the condition or reliability of Big Rivers' generating units, and if so, were the assumptions used in that analysis reasonable?
8. Did the Applicants assume a maximum capacity factors for the Big Rivers coal units in the Phase 2 and 3 analyses? Historically, Big Rivers' coal units have had very high capacity factors as shown in the following table.

Big Rivers Coal Units - Capacity Factor (%)

	D B Wilson	Kenneth C. Coleman (1)	Kenneth C. Coleman (2)	Kenneth C. Coleman (3)	Robert D Green (1)	Robert D Green (2)
2008	82	62	89	80	93	90
2009	75	73	76	67	89	75
2010	92	78	72	81	89	93
2011	94	86	92	84	87	92
2012	84	76	89	83	81	69
2013	91	77	88	84	84	89
Average	86	75	84	80	87	85

Source: Ventyx

9. Did the Applicants analyze purchasing Big Rivers' Wilson Station and converting it to burn natural gas?

E. The Commission should consider whether the Green River NGCC constitutes a wasteful duplication of facilities

To be entitled to a certificate of public convenience and necessity ("*CPCN*") for the Green River NGCC, the Applicants "must demonstrate a need for the proposed facility and the absence of wasteful duplication."[8] The requirement to avoid wasteful duplication is a policy underlying the Commonwealth's territorial law:

> It is hereby declared to be in the public interest that, in order to encourage the orderly development of retail electric service, to avoid wasteful duplication of distribution facilities, to avoid unnecessary encumbering of the landscape of the Commonwealth of Kentucky, to prevent the waste of materials and natural resources, for the public convenience and necessity and to minimize disputes between retail electric suppliers which may result in inconvenience, diminished efficiency and higher costs in serving the consumer, the state be divided into geographical areas, establishing the areas within which each retail electric supplier is to provide the retail electric service as provided in KRS 278.016 to 278.020 and, except as otherwise provided, no retail electric supplier shall furnish retail electric service in the certified territory of another retail electric supplier.[9]

Wasteful duplication of facilities "embraces the meaning of an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[10]

In their joint application, the Applicants allege, "As previously stated, Green River NGCC will be located at KU's Green River Generating Station in Muhlenberg County, Kentucky. There are no like facilities in the vicinity of Green River NGCC and it is not anticipated that Green River NGCC will compete with any other public utilities, corporations or persons." However, the map the Applicants filed as Exhibit 4 to their joint application clearly shows that there are Big Rivers' generating facilities in close proximity to the proposed location of the Green River NGCC. Given the energy and capacity available from the Big Rivers generating stations, the Commission and the intervenors should investigate whether the Green River NGCC would be a wasteful duplication.

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[8] *Citizens for Alternative Water Solutions v. Kentucky Public Service Com'n*, 358 S.W.3d 488, 490 (Ky. App. 2011).
[9] KRS 278.016.
[10] *Kentucky Utilities Co. v. Public Service Com'n*, 252 S.W.2d 885, 890 (Ky. 1952).

F. There are additional policy considerations the Commission should take into account in reviewing the joint application

The Commission's review of the Applicants' request for a CPCN involves other policy considerations in addition to those discussed earlier in these comments. For example, KRS 278.020 provides, in pertinent part, "The commission, when considering an application for a certificate to construct a base load electric generating facility, may consider the policy of the General Assembly to foster and encourage use of Kentucky coal by electric utilities serving the Commonwealth."[11]

Additionally, as discussed in Big Rivers' reply to the Applicants' response to Big Rivers' motion to intervene, this case implicates statewide interests. The Commission has recognized the need for "a more cooperative approach in which the utilities work together to meet the needs of the entire state."[12] The Commission applied that approach in reaching the decision to delay the completion of LG&E's Trimble 1.[13] In that decision, the Commission concluded that it was required to consider "options developed with a statewide perspective."[14] In concluding that completion of Trimble 1 should be delayed by three years, the Commission acknowledged that its decision would add to the ultimate cost of completion of the plant, but held:

> However, the Commission believes the cost will be outweighed by the benefits that accrue to LG&E ratepayers, as well as other Kentucky ratepayers, by using the current abundant generating capacity in Kentucky to develop a statewide planning strategy.[15]

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[11] KRS 278.020(1).

[12] Order dated October 9, 1986, in *In the Matter of: An Inquiry Into Kentucky's Present and Future Electric Needs and the Alternatives for Meeting Those Needs*, Administrative Case No. 308, at p. 2.

[13] Order dated October 14, 1985, in *In the Matter of: An Investigation and Review of Louisville Gas and Electric Company's Capacity Expansion Study and the Need for Trimble County Unit No. 1*, PSC Case No. 9243.

[14] *Id.* at p. 21.

[15] *Id.* at pp. 21-22.

In reviewing the Applicants' request in this case for a CPCN to construct a new natural gas-fired generating station, the Commission should consider the policy of the Commonwealth to foster and encourage use of Kentucky coal, and it should apply a statewide perspective to ensure the best interests of all ratepayers in the Commonwealth are taken into account.

On this the 4th day of April, 2014.

Respectfully submitted,

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Exhibit A
Revised Example from Joint Applicants' Response to AG 1-126

Risk factor		50%
Interest rate for long-term debt		3.75%
Return on equity		10.5%
Tax rate		38.9%
target debt ratio		45.7%
Hypothetical Capacity payment ($/kW-year)		10
Hypothetical capacity (MW)		500
Term (year)		20
		2016
Annual capacity payment ($)		5,000,000
Imputed Debt Adjustment ($)		*2016*
1) Cost of Equity Offset to 20-year PPA Imputed Debt		
PV of Annual capacity payment ($)		69,481,021
Imputed Debt Risk Factor		50%
Imputed Debt		34,740,511
Required Equity Offset		54%
Required Equity Offset		18,874,519
Cost of Equity		10.50%
Tax Gross Up		38.90%
Incremental Revenue Requirement		3,243,575
2) Reduction in Debt from Applying Equity Offset		
Reduction in Debt from Equity Offset		(18,874,519)
Cost of Debt		3.75%
Incremental Revenue Requirement		(707,794)
Resulting Incremental Debt Ratio		
Debt		
Imputed		34,740,511
Reduced		(18,874,519)
Net	45.7%	15,865,991
Equity		18,874,519
Total		34,740,511
Net Incremental Revenue Requirement		2,535,781

Exhibit B

Revenue Requirement of Imputed Debt Under Alternative Assumptions

	2016 Revenue Requirement
Example in response to AG Q 126	$3,243,575
Accounting for debt reduction	$2,535,781
5 year term	$818,106
25% risk factor	$409,053