STATE OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

Joint Application of Louisville Gas & Electric	**)**	
and Kentucky Utilities Company for a	**)**	
Certificate of Public Convenience and	**)**	
Necessity and Site Compatibility Certificate	**)**	**Case No. 2011-00375**
for the Construction of a Combined Cycle	**)**	
Plant at the Cane Run Station and the	**)**	
Purchase of Existing Simple Cycle	**)**	
Combustion Turbine Facilities from	**)**	
Bluegrass Generation Company	**)**	

DIRECT TESTIMONY OF PAUL CHERNICK

ON BEHALF OF

SIERRA CLUB AND

NATURAL RESOURCES DEFENSE COUNCIL

Public Version—Confidential Information Redacted

Resource Insight, Inc.

DECEMBER 20, 2011

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power-supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, integrated resource planning, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation-program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified more than 250 times on utility issues, before regulators in more than thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

II. Introduction

Q: For whom are you testifying?

A: My testimony is sponsored by Sierra Club and Natural Resources Defense Council.

Q: What is the purpose of your direct testimony?

A: My clients asked that I review the adequacy of the recent request for proposals process of Louisville Gas & Electric and Kentucky Utilities Company (collectively, the Companies), specifically with regard to the treatment of renewable resources in the screening of offers.

Q: Over what period of time have you reviewed the Companies' filings in this proceeding?

A: My clients retained me immediately upon being granted intervention on December 14, 2011, six days before the due date for this testimony. I promptly reviewed the redacted application and the responses to both sets of Staff discovery. Unfortunately, the redactions eliminated almost all the information of interest for my review. The confidential version of the application was provided to me on December 16 2011. The Companies responded to my clients' discovery on December 19, the day before my testimony was due.

As a result of the short period available for me to review the record, including the responses to my clients' discovery, I may need to supplement my direct testimony. If so, I will provide that supplement well in advance of the Companies' rebuttal testimony, so as not to delay the case schedule.

Q: What specific issues does your testimony address?

A: Based upon my brief review of the Companies' 2011 Resource Assessment (Exhibit DSS-1), along with the Companies' 2011 Integrated Resource Plan, I have concerns about the following two broad areas: the treatment of future environmental costs in the screening of resources and the treatment of various cost risks. The next two sections describe those concerns.

Q: What recommendations do you have for the Commission in this proceeding?

A: Unless the Staff or some other party identifies a problem in the pricing of the Bluegrass purchase, I believe the low price of that purchase and the possibility that the plant would not be available for purchase in the future argue for approval of the Bluegrass transaction. On the other hand, I recommend that the Commission defer any approval of the Cane Run combined-cycle plant, pending further analysis of the points I have raised, along with those raised in the testimony of Sierra Club and Natural Resources Defense Council witness Dylan Sullivan. The Commission does not currently have enough information to determine whether construction of the new Cane Run plant is beneficial in addition to the implementation of all cost-effective energy efficiency and a substantial purchase of renewable energy.

Procedurally, the Commission would need to decide whether to approve the Bluegrass transaction and leave this docket open for additional fact finding on Cane Run and alternatives, or to close this docket and invite the Companies to file a more complete analysis of Cane Run, renewables, and efficiency.

III. Future Environmental Costs

A. Conventional Pollutants

Q: How should the Companies reflect future environmental costs and requirements in resource planning?

A: Those considerations affect the cost-effectiveness of resources through two basic effects, each of which can manifest in a number of ways. First, environmental requirements may trigger retirements and retrofits prior to the selection of new resources, in ways that increase the cost-effectiveness of additional resources. Such changes to the Companies' existing resources may include the following:

- plant retirements, which advance the need for new capacity and increase marginal dispatch costs in the hours in which the retired plants would otherwise have run;
- retrofits that reduce plant capacity (e.g., increased internal plant loads to operate scrubbers), which have effects much like retirements, although on a smaller scale;
- retrofits that increase plant heat rate, by using electricity and/or steam;
- retrofits that increase variable operating costs (e.g., scrubber limestone, SCR ammonia and catalyst replacement, using up space in existing landfills, activated carbon) for plants that continue to operate, increasing marginal costs;

- requirements for emission allowances, which increase the effective cost of each MWh generated, much like variable O&M;
- annual operating limitations to keep emissions, cooling-water usage, or other environmental effects within permitted levels.

Second, the selection of new resources may allow the avoidance of some environmental retrofits, either by allowing retirement of the existing plants or by allowing continued operation within permitted levels without further retrofits.

Q: What environmental regulations and requirements are currently pending?

A: The major pending regulations of concern for the Companies' plants include the following:

- The Cross-State Air Pollution Rule (CSAPR), which sets annual emission limits for each thermal unit for annual SO_2 emissions, annual NO_X emissions, and seasonal NO_X emissions, to reduce fine-particulate and ozone pollution. Emission allocations can be traded between plants within Kentucky and can be traded across state lines to a limited extent. Current prices for those emissions allowances in 2012 are $250/ton for SO_2, $550/ton for annual NO_X, and $625/ton for seasonal NO_X. Interstate trading becomes more restricted starting in 2014. For Kentucky and 15 other states, the SO_2 emission limits also become more stringent in 2014. The limits on NO_X emissions are designed to improve air quality in the areas that violate an older 0.080-ppm national-ambient-air-quality standard for ozone. A tighter 0.075-ppm standard was adopted in 2008 (72 Fed. Reg. 16, 436 (March 27 2008)), but the additional areas not in compliance with that standard have not been formally listed. The EPA has scheduled another revision of this ozone standard for 2013, and the agency's scientific advisors have already recommended a standard between 0.060 and 0.070 ppm. The stricter ozone standards (and potentially stricter particulate standards) would result in tighter emission limits under future rounds of the CSAPR.

- The requirement for Maximum Achievable Control Technology to control hazardous air pollutants from power plants. The final rules are to be released roughly contemporaneously with the filing of my testimony and are expected to require activated carbon injection and baghouses to capture mercury and other metal emissions, as well as some control of acid gases.
- The requirement for improved screens to limit impingement of aquatic organisms and the analysis of entrainment of smaller organisms in power-plant cooling system, a rule that only appears to affect Mill Creek 1 among the Companies' units.
- Pending requirements for improved handling of coal-plant wastes to minimize run-off (such as by replacing waste ponds with lined and monitored landfills) and the contamination of surface and ground waters.

Q: How does the Resource Assessment incorporate future environmental costs?

A: The Resource Assessment does not provide a clear summary of the effects of the Companies' plans for environmental compliance on dispatch of its existing system, and hence the energy costs avoided by new resources. The Resource Assessment, the Application, and the testimony of Company Witness David Sinclair indicate that the analysis reflects the retirement of six old coal units (Cane Run 4–6, Green River 3 and 4, and Tyrone 3), totaling 797 MW, by the end of 2015.

The Companies' tabulations of the future capacity of existing resources include annual variations in capacity (both up and down), with a net reduction of 32 MW from 2012 to 2018 (e.g., Resource Assessment Table 7). I have not found any breakdown of these changes by unit. It is not clear whether this reduction reflects all the effects of pending environmental retrofits.

The Resource Assessment does not provide any information regarding the Companies' modeling of the variable costs of the environmental controls, or their effects on heat rate, on the avoided production costs used in evaluating potential resources. I would expect to see prices for allowances under CSAPR listed among the "Key Assumptions" in Section 7 or Appendix B to the Resource Assessment, but allowance prices are not mentioned anywhere.

Finally, it does not appear that the Resource Assessment accounted for the possibility that additional supply resources would allow the Companies to retire such units as Mill Creek 1 and Brown 1 and 2, avoiding the environmental upgrades that are otherwise likely to be needed for those units.[1]

B. Treatment of Greenhouse Gas Regulation

Q: How does the Resource Assessment deal with the possibility that the Companies will be subject to future regulations to control greenhouse-gas regulations?

A: The Resource Assessment does not contain any reference to greenhouse-gas regulations, emission limits, caps, fees, or any other constraints over the next 30 years.

Q: Is that a reasonable assumption at this time?

A: No. The EPA has accepted the responsibility to regulate greenhouse-gas emissions from large sources (which would include most of the Companies' fossil power plants). The details of EPA's regulatory scheme are still under develop-

[1]Reducing the Companies' energy requirements through enhanced energy-efficiency programs would also facilitate retirement of those units and avoidance of environmental retrofits.

ment, and whatever EPA develops under its current authority and court mandates is likely to be superseded by future legislative action.

Q. What is the current status of EPA's obligation to address carbon emissions?

A. The EPA is in the process of promulgating greenhouse gas New Source Performance Standards under the federal Clean Air Act. The standards are likely to require new sources to take particular steps to limit their CO_2 emissions. The standard will also likely apply to existing sources that are modified in ways that increase greenhouse-gas emissions over a certain threshold.

In conjunction with this requirement, the EPA is slated to issue binding emission guidelines that will regulate greenhouse-gas emissions from electric generating units regardless of whether the source undergoes a major modification.[2] Either regulatory approach is likely to establish some cost for emitting CO_2 or to achieve required reductions in such emissions. Therefore assuming a cost of zero for future greenhouse gas regulation is unreasonable.

Q: Given the uncertainties, is it possible that the appropriate estimate of the Companies' costs of complying with greenhouse-emissions rules is zero?

A: No. It is possible that future charges for carbon emissions would be zero, although I believe that is unlikely. But it is certainly possible that the costs will be positive, and they may be very large. The probability-weighted average of those potential future costs should be included in the reference case, and the wide range of possible costs should be reflected in the risk analysis.

Q: Do other major utilities around the country include the cost and risk of carbon regulation in resource planning?

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[2]See the EPA's 2011 "Settlement Agreements to Address Greenhouse Gas Emissions from Electric Generating Units and Refineries: Fact Sheet" (online at www.epa.gov/airquality /pdfs/settlementfactsheet.pdf, accessed 12/20/2011).

A: Many major utilities expect that carbon caps or taxes are likely in the future and thus include one or more CO_2 prices in resource evaluation. Some examples within the last year, mostly from integrated resource plans (IRPs), are as follows:

- Duke Energy Carolinas September 2011 South Carolina IRP (at 100–101) assumed a CO_2 price starting at $12/ton in 2016 and increasing to $42/ton by 2031, with higher CO_2 price assumptions in sensitivity analyses.
- Georgia Power's August 2011 IRP (at 159–160) modeled four different CO_2 price levels ranging from $0 to $30/ton starting in 2015 to "span the plausible short term and long term range of CO_2 requirements."[3]
- Delmarva, in its December 2010 Delaware IRP assumed a federal CO_2 price of $20 per ton in 2018, increasing to $25 per ton by 2020.[4]
- Ameren Missouri's February 2011 IRP (AT 31) includes a CO_2 cap-and-trade case with a price of $7.50/ton in 2015, increasing to $47/ton in 2040.
- The Tennessee Valley Authority's March 2011 IRP evaluated resources with eight CO_2 price-scenarios ranging from a $0/ton low case to a high case with prices rising from $17 per ton in 2012 to $94 per ton by 2030.[5]
- PacifiCorp's March 2011 Utah IRP (at 159–160) used four CO_2 price cases, ranging from no CO_2 price, to as much as $25/ton in 2015, with various escalation rates. PacifiCorp utility also modeled two scenarios involving hard caps on overall CO_2 emissions.

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[3]Georgia Power's Application for Decertification and Updated Integrated Resource Plan, Georgia PSC Docket No. 34218 (Aug. 4, 2011) at 37. Georgia Power is a subsidiary of the Southern Company.

[4]Delmarva Delaware IRP Filing Resource Modeling—Supporting Documentation (Dec. 1, 2010) at 16–17. Delmarva is a subsidiary of PEPCo Holdings.

[5]Tennessee Valley Authority Integrated Resource Plan: TVA's Environmental and Energy Future (Mar. 2011), at 96.

- Duke Energy Ohio July 2011 IRP included a CO_2 price beginning in 2016.[6]
- The Avoided Energy Supply Cost Report (July 2011), sponsored by the New England utilities (including NStar, National Grid, Northeast Utilities, Central Maine Power and United Illuminating), included a base CO_2 price of $2/ton in 2012, rising to $15/ton in 2018 and $39/ton in 2026, as well as low and high cases with prices of $2/ton and $64/ton in 2026 (all in constant 2010 dollars).[7]

Many other IRPs issued in 2010 or earlier also include carbon prices.

IV. Treatment of Risk

Q: How does the Resource Assessment treat risk?

A: I have not found any explicit treatment of risk in the Resource Assessment.

Q: What risks that arise from the Companies' existing and proposed new resources would be mitigated by renewable resources?

A: Renewable resources are not subject to fluctuations in fuel costs. Most of the Companies' existing resources are fueled by coal or natural gas, while gas would fuel both of the plants proposed in this proceeding. Natural gas is the fuel supply for more of the marginal energy supply than for the Companies' total energy supply. In addition, the cost of economy power purchases is likely to be determined primarily by the price of gas in high-load hours and by coal in the low-load hours. As has been demonstrated over the last decade, fuel prices can

[6] Duke Energy Ohio, Inc., 2011 Electric Long Term Forecast Report and Resource Plan, Ohio PUC Case No. 11-1439-EL-FOR (July 15, 2011), at 186.

[7] Hornby, Rick, Paul Chernick, Carl Swanson, et al. 2009. "Avoided Energy Supply Costs in New England: 2009 Report." Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid.

change rapidly and unexpectedly. For example, Northern Appalachian high-sulfur spot coal prices rose from about $45/ton in late 2006 to over $120/ton in the summer of 2008, fell back into the $45/ton range in early 2009, and is now up to about $80/ton

High fuel prices, either prolonged or sporadic, create financial and economic stress of electricity consumers.

Q: Other than fuel prices, are there other important sources of cost risk from the Companies' fossil generation portfolio?

A: Yes. The Companies' thermal power plants and economy power purchases are also subject to environmental-compliance risks that do not affect the major renewable technologies, wind and solar. Those risks include, for example, uncertainty regarding the allowance prices for the CSAPR under the current rules, under the tighter CSAPR allowance allocations to be established in the future, and the very broad uncertainty regarding future carbon emissions regulations.

More generally, the Companies' energy supply portfolio is highly concentrated in coal and, to a lesser extent, gas. A highly concentrated portfolio is subject to greater risk that one with a more diverse mix.

Q: Does the Companies' use of multiple fuel-price forecasts constitute a risk analysis?

A: No. Each of the fuel-price forecasts used in the Resource Assessment represents the expectations of one analyst or another (the Companies, Wood/PIRA, or CERA) regarding the average or most-likely prices in the future. None of these analyses is described as representing a high-price case in response to supply restrictions or high demand (e.g., China's demand for coal, or increased demand for gas by electric generators).

In addition, the Companies applied the alternative fuel-price forecasts only in the Final Phase II analysis, after the [redacted] in Phase I and Initial Phase II. Hence, even the variation in base-case fuel forecasts did not affect the [redacted].

Q: Is there a difference in the risk characteristics of the two resources that the Companies have selected and of purchases of renewable resources?

A: Yes. For purchases from renewable power plants, such as wind farms, utilities generally pay a contract price per MWh delivered. Anything that increases the cost of the power, or reduces the availability of energy output, is the problem of the resource owner. The risks of building, maintaining, and operating the plant is shifted to the seller. If the plant does not work, the Companies and their customers do not pay; if the plant is expensive to operate, the Companies and their customers pay only the contracted price.

In contrast, in purchasing the Bluegrass plant, the Companies are taking on the risks of being the plant operator. For the Cane Run combined-cycle plant, the Companies would incur all the risks of licensing, building, and operating the plant. Almost all of those risks are passed on to ratepayers, who generally wind up paying the full cost of utility-owned power plants whether the plants operate well or not.

Q: Did the Companies take the different risks of plant ownership and power purchases in the Resource Assessment?

A: No.

Q: How should the Companies have incorporated risk in the analysis?

A: The Resource Assessment could have dealt with risk in several ways. For example, the Companies could have estimated the effect of high fuel prices and allowance prices on the total cost-effectiveness of renewable options and on the variability of rates from one year to the next. Alternatively, the Companies could apply a fixed percentage discount to the price of any fixed-price resource whose cost does not vary with fuel price or emission allowance prices.

V. Renewable-Energy Potential and Costs

Q: Are large amounts of renewable energy available?

A: Yes. As summarized in, nearly 5,000 MW of utility-scale wind capacity are on line in the states surrounding Kentucky, of which 750 MW were added in 2011. Another 1,100 MW are under construction, and 32,000 MW are in the transmission queues in those states. See Table 1. Note that no wind capacity is on line or under development in Kentucky.

Table 1: Megawatts of Wind Generation Around Kentucky

State	On Line	Recent Additions 2011	Recent Additions 2010	Under Construction	In Queue
Ill.	2,436	389	498	611	16,284
Ind.	1,339	303	905	-	8,426
Ky.	-	-	-	-	-
Mo.	459	2	149	-	2,051
Ohio	67	57	3	352	3,683
Tenn.	29	-	-	-	-
Va.	-	-	-	38	820
W. Va.	431		101	147	1,045

Source: American Wind Energy Association, State Fact Sheets

Larger amounts of wind energy are on line and under development in other states of the MISO and PJM regions.

Utilities serving areas contiguous with the Companies are also purchasing wind energy from further afield. The Tennessee Valley Authority, for example, has 1,565 MW of wind farms under contract, comprising

- 300 MW on line in Illinois, with another 350 MW under construction,

- 115 MW on line in Iowa, with another 184 MW under construction,
- 366 MW under construction in Kansas,
- 250 MW under construction in South Dakota.[8]

Additional transmission currently under development will allow even more of the low-cost wind energy from the Plains states (such as Kansas, Oklahoma, Nebraska and the Dakotas) to reach the Midwest, including Kentucky.

Q: Are the costs of wind energy competitive with other sources?

A: Yes. Utilities such as PacifiCorp and TVA have acquired large amounts of wind energy for economic reasons, independent of any state requirements for renewable energy.

The costs of renewables have fallen dramatically over time. For wind, increased production of turbines, increased turbine size, and taller towers have all reduced the cost of power per MWh produced. The following are examples of the costs of power from recent projects:

- In 2007 through 2010, Oklahoma Gas and Electric (OG&E) paid about $25/MWh for energy from the 50 MW NextEra Sooner project.[9]
- In 2010, OG&E paid about $47/MWh for power from the 152 MW Keenan project.[10]
- Minnesota Power has recently estimated that its latest wind project, the 105 MW Bison 3, will cost $28/MWh.[11]
- Kansas City Power & Light has contracted with Duke for $38/MWh from the 131 MW Cimarron II wind farm.[12]

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[8] http://www.tva.gov/power/wind_purchases.htm, accessed 12/20/2011.

[9] OG&E FERC Form 1 reports, various years, at 326–327.

[10] OG&E FERC Form 1 reports, various years, at 326–327.

[11] "Wind project to Cut Overall Costs in Minnesota," Megawatt Daily, October 21, 2011, at 10.

The costs of solar photovoltaic systems are also falling rapidly. While solar energy is still more expensive than wind, it is also more valuable, because the energy production is predominantly during the higher-priced on-peak hours. Since solar output is highly coincident with summer peak loads, solar installations at or near customer premises can avoid transmission and distribution costs, as well as reducing peak and energy line losses.

Q: Does this conclude your testimony?

A: Yes, at this time. Given the circumstances I describe above in Section II, I may need to supplement this testimony.

[12]"Wind Turbine Glut, Greater Efficiency Drive Down Prices," Power Finance & Risk, 9/5/2011, at 1.