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March 21, 2008

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MAR 24 2008
PUBLIC SERVICE
COMMISSION

RE: Case No. 2007-00477

Dear Ms. O'Donnell:

Please find enclosed for filing with the Commission in the above-styled proceeding an original and ten (10) copies of the Response of the Sierra Club to the first data request of the Public Service Commission Staff. A copy of this document has been mailed to all parties listed on the attached Certificate of Service.

Sincerely,

Stephen A. Sanders

Stephen A. Sanders
Attorney at Law

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MAR 24 2008
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION

In the Matter of:

AN INVESTIGATION OF THE ENERGY AND REGULATORY ISSUES IN SECTION 50 OF KENTUCKY'S 2007 ENERGY ACT

Administrative Case No. 2007-00477

RESPONSE OF SIERRA CLUB TO PUBLIC SERVICE COMMISSION STAFF'S FIRST DATA REQUEST

The Sierra Club, by counsel, submits a partial response to the First Data Request of the Public Service Commission Staff. The Sierra Club requests a one week extension of time to complete the responses to the Staff's Data Request. This extension of time is necessary because two people who are working on this matter on behalf of the Sierra Club team were unavailable during the week beginning March 16th, and the Staff's Data Requests could not be answered prior the 16th. The Sierra Club also requests that this Response be accepted late because of a technical problem with counsel's computer which prevented the placing of the articles on the CD in time to be filed prior to this date.

1. Refer to pages 2-3 of the Direct Testimony of Wallace McMullen ("McMullen Testimony"). Provide the Abt Associates study quoted on page 2 of the testimony, as well as the Clean Air Task Force study referred to in footnote 3 on page 3.

RESPONSE:
Attached is a CD containing the studies.

2. Refer to the McMullen Testimony, page 25, lines 13-17. Provide the document titled, "The Carbon Principles.".

RESPONSE:

Attached is a CD containing the document.

3. Provide the Synapse study referenced on pages 25-26 of the McMullen Testimony and cited in footnote 66.

RESPONSE:

Attached is a CD containing the study.

4. Refer to the McMullen Testimony, page 30, lines 19-21. Provide a list of each state regulatory commission that requires electric utilities to recognize externalities as part of an integrated resource plan or to justify a certificate of need to construct new generation.

   a. For each such commission, identify the externality that is required to be recognized and the cost assigned to each environmental or public health item.

   b. Identify the state statute or provide the commission decision orders requiring electric utilities to recognize such externalities.

RESPONSE:

The Sierra Club requests an extension of time to provide this information.

5. Refer to pages 3-5 of the Direct Testimony of Andy McDonald ("McDonald Testimony") concerning carbon emissions, the costs of controlling them, and the impact of such costs on utility rates. Provide any data or evidence in the Sierra Club's possession which reflects, in any way, the estimated future impacts of carbon emissions on Kentucky electric utilities jurisdictional to the Commission. Include a narrative description of any studies, schedules, spreadsheets, or work papers that may be included in the response.

RESPONSE:

Following are descriptions of a number of reports which express estimates for the future cost of carbon emissions and the effect this will have on electricity prices. The complete documents as attached exhibits.

Rate Design and Ratemaking Alternatives Technical Report, LaCapra Associates, Kentucky Governor's Office of Energy Policy, November 21, 2007. (Exhibit 1)

La Capra Associates was retained by the Kentucky Governor's Office of Energy Policy to study "the potential financial, social and economic impacts of alternative rate design structures and ratemaking methodologies that may encourage increased utilization of and investment in cost effective energy efficiency and other demand response resources." (p. 1) In this report La Capra analyzed the potential rate impacts of future federal carbon regulations. The La Capra report states that there is an increasing likelihood for federal policies to limit greenhouse gas emissions.

La Capra looked at the impacts of several pending climate change bills on the cost of carbon emissions and how these would affect electricity rates in Kentucky. They report on studies indicating that various bills would result in an initial carbon cost ranging from $5 to $25 per ton, and these costs would grow to $7 to $50 per ton after 10 years. La Capra concludes that with carbon costs ranging from $10 to $40 per ton, the marginal cost of energy would rise 15% to 65%. This would mean a rate increase of approximately 0.8 cents per kWh to 3.2 cents per kWh. (p. 13)

The La Capra Report states:

> "The cost that is most relevant to designing rates that provide appropriate price signals for energy efficiency is the long-run marginal cost of supply. The marginal cost of supply (also referred to as generation) includes the cost of additional energy (primarily fuel) and the cost of additional capacity. For customers to make efficient long-run decisions about appliance purchases and housing stock, they need to be able to compare the additional amount they will spend for the purchase with the savings in electric bills that will result from the purchase. They cannot make efficient decisions if rates do not provide them with price signals regarding future electric costs. Thus rates should include a reflection of marginal capacity costs. Other costs that should be considered are those that may result from federal action regarding environmental regulations. Federal, state, or local regulations regarding air emissions, water resources, land resources, and even aesthetics may all increase the cost of electricity. If the impact of likely and potential new regulations, particularly environmental regulations on Kentucky utilities is reflected in the utilities' projections of supply costs and of marginal costs, the next DSM screening analyses would find that many more energy efficiency measures would appear cost-effective and would pass the screening tests." (p.10)

The report continues:

> "We expect that the marginal cost of supply is higher than average supply cost in Kentucky. This is true of the marginal cost of energy, as more than 90% of the energy is produced by coal baseload generation, but during some peak hours the marginal cost will most likely be determined by natural gas-fired generation. It is also true of the marginal cost of generating capacity. Adding new capacity is also much more expensive than the average capacity cost of existing generation, which as noted above has been significantly partially depreciated due to age. New generation capacity is more expensive than older generation. Moreover, the cost of building new generation has risen sharply in the last few years as a result of escalating material costs, a weakening U.S. dollar, and increasing labor costs. Based on the Handy Whitman Index©, a set of indices that track the cost of various generation components, the graph below shows that the cost of steam units increased by about 25% between 2004 and 2007.14 Furthermore, gas turbine costs experienced an 18% increase just in the past year. The extent of future increases is difficult to estimate, but growth in global demand for materials will likely continue to put

pressure on new generation costs. This translates to even higher marginal costs for new capacity than previously estimated by Kentucky utilities." (p. 11)

Carbon Management Report, Kentucky Governor's Office of Energy Policy, 2008. (Exhibit 2)

Kentucky House Bill 1 (HB 1) directed the Governor's Office of Energy Policy and other state agencies, including the Public Service Commission, to prepare a report concerning carbon management research and technologies in coal-fired power plants. The report reviews activities at the state, regional, and national levels to address climate change and notes, "The momentum for action at the federal level, however, is escalating." (p. 1) The report identifies the regulation of carbon emissions as an issue of importance that will significantly impact the cost of energy in the state and how it is generated. One potential strategy for dealing with carbon emissions from coal combustion is the use of carbon capture and sequestration technology at coal power plants. The report states, "Estimates are that the cost of adding carbon capture and sequestration capability at existing coal-fired facilities will increase electricity costs of between 50% and 300%." (p. 3)

Gambling with Coal: How Future Climate Laws Will Make New Coal Power Plants More Expensive, Freese, Barbara, and Clemmer, Steve, Union of Concerned Scientists, September 2006. (Exhibit 3)

Gambling With Coal argues that the regulation of carbon emissions is highly likely in the next few years and will make investments in new coal power plants very risky and imprudent. The report begins by reviewing the scientific evidence which establishes the need for policies limiting CO2 emissions in the present and dramatically reducing those emissions over the next four decades. It then describes international efforts to reduce global greenhouse gas (GHG) emissions and state and regional efforts within the U.S. It mentions the Regional Greenhouse Gas Initiative (RGGI) under which eight North Eastern states have agreed to begin capping CO2 emissions in 2009 with an initial goal of cutting emissions 10% by 2019. California, along with other Western states, is also implementing policies to reduce GHG emissions. Meanwhile Congress is moving towards policies to limit GHG emissions (seven bills had been proposed to this end as of July 2006).

The report highlights that there is broad support for federal CO2 limits, including many electric utilities. Five of the nation's ten largest private power providers support mandatory limits on CO2 from power plants. The investment community is also deeply concerned about the risks carbon regulation poses to the electric power industry, and the report cites large institutional investors questioning the wisdom of building new coal power plants. In light of this, the question has become when and how, rather than if, CO2 will be regulated in the U.S.

The report then discusses why the future costs of CO2 regulation must be part of any realistic estimate of a proposed coal plants operating costs. It describes how numerous utilities are already factoring these costs into their planning process. The report reviews estimates from many sources of the possible costs of federal CO2 emission limits. The references to these numerous studies are available in the report on pages 24 – 25 and would provide detailed analyses of this question for PSC staff.

A review of ten models prepared to simulate the future cost of CO2 emissions was conducted by Synapse Energy Economics in May 2006. (Their full report is attached as Exhibit 4). Synapse then presented its own projections for low, mid, and high-range CO2 emissions costs. Synapse believes that their projections "represent the most reasonable range to use for planning purposes, given all of the information we have been able to collect and analyze bearing on this important cost component of future electricity generation." (*Gambling With Coal*, p. 25) Synapses projections range from $0 - $10 per ton CO2 in 2010 and by 2030, the range is $20 - $50 per ton.

"When Synapse's cost projections are levelized over 30 years to 2005 dollars, the low CO_2 cost projection is $8.50/ton, the mid-range projection is $19.60/ton, and the high projection is $30.80/ton." (Ibid, p. 26) Synapse's projections are within the range of cost assumptions used by various utilities and the Northwest Power and Conservation Council, as reported in *Gambling With Coal.*

The report projects that these carbon costs would add 17% - 62% to the base price of coal generated electricity (an increase of $55.67/MWh to $77.11/MWh) (the assumptions behind these calculations are explained on page 29).

An important point made in the report is that Synapse's analysis, as well as all of the other projections for the cost of carbon emissions, is based on GHG regulation schemes which will not reduce carbon emissions enough to avoid dangerous climate change. These various analyses are based on the goals of particular bills in Congress, which all fall short of achieving the GHG reductions climate scientists say are needed. The implication is that, if the time comes when strategies are implemented to achieve these more far-reaching goals, the cost impacts on carbon (and coal-generated power) could be even greater than what's described here.

The report continues with a discussion of how energy efficiency and some renewable energy sources are already cheaper than coal generation, and when carbon costs are factored in, these alternatives become even more cost-effective. These carbon-free alternatives are also less risky than building new coal generation, because they are insulated from impending carbon regulations.

The risks now inherent in building new coal generation lead the authors to the following recommendations:

> "Utilities should factor future CO2 costs into their resource planning and procurement, aggressively pursue conservation, efficiency and renewable energy, and at the very least defer making major coal plant construction decisions until they have a clearer picture of the regulatory risks and technological opportunities ahead."
>
> • "Regulators should insist that utilities take the above steps. They should also protect ratepayers by refusing to authorize the construction of new conventional coal plants, which are premised on the regulatory conditions of the past, not those of the future. At the least, they should warn utility managers that shareholders will bear the risk that coal investments will result in excess carbon costs."
>
> • "Investors and shareholders should recognize the inevitability of CO2 regulations and understand that utilities that behave imprudently by building coal plants

despite these costs would, under existing regulatory principles, be prevented from recovering at least a portion of such costs in their rates. Shareholders should question utility management closely on how they are assessing and managing carbon risks, and require reporting and accountability. Long-term investors should favorably regard companies who are proactively considering and managing these risks effectively."

- "Ratepayers and consumer groups should realize that the utilities building new coal plants will seek to recover all their costs, including CO2 regulatory costs, from ratepayers. While legal principles support denying rate recovery of these costs, history shows that these cases are extremely contentious and expensive. A far better way for ratepayers and consumer groups to protect themselves from such financial risk is by resisting the construction of new conventional coal plants in the first place and by supporting investments in cleaner alternatives such as efficiency and renewable energy."

"Building a major energy resource – especially one that costs as much and lasts as long as a coal plant -- is unavoidably an exercise in predicting the future. It cannot be prudently done without objectively analyzing the trends and potential risks that will shape the decades ahead. In the case of new coal plants, the critical trends are undeniable and moving with unstoppable momentum: CO2 levels are rising to levels unseen on the planet in millions of years, global temperatures are setting new records, scientific evidence showing that our current energy path is leading to dangerous climate changes is mounting, and the policy response at every level of government is accelerating. To assume in the face of these trends that a new coal plant could be put into service and allowed to emit millions of tons of CO2 for free for the next few decades is reckless, to say the least. New conventional coal plants in the age of global warming are not just bad policy – they are a bad investment, and one we cannot afford to make."

Direct Testimony of David A. Schlissel and Anna Sommer, Synapse Energy Economics, Inc., Before the South Dakota Public Utilities Commission, Case No EL05-022, May 19, 2006. (Exhibit 5)

David Schlissel and Anna Sommer provided testimony on behalf of Minnesotans for an Energy Efficient Economy and three other organizations in the case of a siting permit for the Big Stone II Project, a proposed new coal fired power plant in South Dakota. Their testimony provides a clear description of a case in which a new coal fired power plant has been proposed without consideration of the costs of carbon regulation. In their testimony, they detail the financial risks to the power company's owners and ratepayers. They argue that the Company's owners completely failed to consider these risks and had therefore proposed a project which should not be approved by the South Dakota PSC.

Table 1 reproduced from their testimony shows the CO2 cost ranges being used by various utility companies. Schlissel and Sommer stated that their analysis found that the cost of carbon regulation was likely to add from $35 million to $137 million to the annual, levelized costs of operating the Big Stone II power plant. (p.24)

The full text of this testimony is included as Exhibit 5.

Table 1. Carbon Dioxide Costs Used by Utilities (from testimony of Schlissel and Sommer, p. 15)
CompanyCompany CO2 emissions trading assumptions for various years ($2005)
PG&E*)$0-9/ton (start year 2006
Avista 2003* $3/ton (start year 2004)
Avista 2005 $7 and $25/ton (2010) $15 and $62/ton (2026 and 2023)
Portland General Electric*$0-55/ton (start year 2003)
Xcel-PSCCo $9/ton (start year 2010) escalating at 2.5%/year
Idaho Power* $0-61/ton (start year 2008)
Pacificorp 2004 $0-55/ton
Northwest Energy 2005$15 and $41/ton
Northwest Power and Conservation Council$0-15/ton between 2008 and 2016 $0-31/ton after 2016
*Values for these utilities from Wiser, Ryan, and Bolinger, Mark. "Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans." Lawrence Berkeley National Laboratories. August 2005. LBNL-58450. Table 7. Other values: PacifiCorp, Integrated Resource Plan 2003, pages 45-46; and Idaho Power Company, 2004 Integrated Resource Plan Draft, July 2004, page 59; Avista Integrated Resource Plan 2005, Section 6.3; Northwestern Energy Integrated Resource Plan 2005, Volume 1 p. 62; Northwest Power and Conservation Council, Fifth Power Plan pp. 6-7. Xcel-PSCCo, Comprehensive Settlement submitted to the CO PUC in dockets 04A-214E, 215E and 216E, December 3, 2004. Converted to $2005 using GDP implicit price deflator.

6. Refer to page 6 of the McDonald Testimony, specifically, the quote beginning on line 18. There is no closing quotation mark prior to the opening quotation mark for the paragraph beginning on line 9 of page 7 of the testimony. Clarify whether the entire text from line 18, page 6 to line 8, page 7 is a quote from the document cited in footnote 3 on page 7.

RESPONSE:

The entire text in question is a direct quote from the document cited in footnote 3 on page 7.

7. Refer to footnote 3 on page 7 of the McDonald Testimony. Provide the document "Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative" by Susan Zinga and Andy McDonald, along with a biography on Susan Zinga.

RESPONSE:

A pdf of the document is attached. The document includes a biography of Susan Zinga.

8. Refer to page 7, lines 17 to 19, of the McDonald Testimony, the two sentences which read, "One commonly hears that Kentucky has poor wind resources, with the exception of the mountaintops in Eastern Kentucky. While this may generally be true, those mountains may offer a substantial number of viable wind energy sites."

   a. Explain in detail the basis for Mr. McDonald's belief that the mountains of eastern Kentucky "may offer a substantial number of viable wind energy sites," (emphasis added) and provide copies of all reports and analyses that support this belief.

   b. Is the amount and frequency of wind the sole criteria for determining whether a wind energy site is viable, or are additional criteria, such as the proximity of transmission lines and the cost effectiveness of the project, considered in determining viability? Explain the response.

   c. Does Mr. McDonald know of any way to scientifically test fo the possibility that a certain site could reliably produce wind energy? Explain the answer.

RESPONSE:

The U.S. Wind Resource Map produced by the National Renewable Energy Laboratory (NREL) of the US Department of Energy (Exhibit 7) indicates that the mountains of Eastern Kentucky along the Virginia/West Virginia border have a "fair" wind resource (that is, they are in Wind Power Class 3). This map was produced using estimates of annual average wind power at 50 meters above the surface and does not provide absolute verification of the wind power resource for any location. Wind energy resources are highly localized and very much influenced by local geographic and climatic conditions. It is generally recommended that a local site analysis be performed for a particular site before investments are made to develop the wind resources.

The area in Eastern Kentucky rated in Wind Power Class 3 encompasses hundreds of square miles. A utility-scale wind turbine (average capacity equal to 750 kW or more) may require one acre to harvest the wind resource for 50 acres. (Source: Ten Steps in Building a Wind Farm, American Wind Energy Association, Wind Energy Fact Sheet, www.awea.org). Illinois has developed 733 MW of wind capacity and over 600 MW were developed in 2007 alone, while most of the state is rated in Class 3, like Kentucky. Although Illinois has a much greater area than Kentucky suitable for wind development, there remain hundreds of square miles of land with potentially viable resources. Exhibits 8 and 9 show the total installed capacity of wind generators in the US at the end of 2007 and 2006. Reviewing these maps in conjunction with the US Wind Resource Map reveals how states such as Illinois, with wind resources comparable to those in Eastern Kentucky, are rapidly developing those resources.

According to conversations I have had with the Governor's Office of Energy Policy, they have commissioned a study of Kentucky's wind resources which will give a higher-resolution and more accurate picture of Kentucky's wind resources.

I am also aware that Genesis Developments is a for-profit business formed to developed utility-scale wind projects in Eastern Kentucky. To date they have not installed any units but they are working towards that goal.

8.b. There are a variety of factors that contribute to determining the viability of a site for wind energy generation. The quality of the wind resource is critical, of course, but there are other critical factors, as well. These include:

- *Environmental and social factors* – environmental assessments are required to determine if the project would cause unacceptable harm to local environmental resources. For example, would it be appropriate to clear a forested mountain top to access the wind resources? How would the wind generator impact the local viewshed and how would the local community feel about that? Are there local raptor populations that could be impacted by the turbines? The presence of numerous mountaintop removal sites in Eastern Kentucky raises the possibility that there are sites already leveled and heavily impacted, upon which wind turbines could be developed with minimal additional impact.
- *Local landowners* – Wind developers must secure the rights to develop a wind project from the appropriate landowners. In many cases the wind lease can provide significant income to the landowner.
- *Access to transmission lines and roads* – Connecting to local transmission lines can be a significant cost for a wind project and potentially a limiting factor at remote sites. Roads are also required for bringing in the heavy equipment needed to install the turbines and also to provide access for maintenance personnel.
- *Permitting* – There are many layers of permitting that must be worked through to site a wind facility and this is not an insignificant factor for a project developer.
- *Financing* – Access to capital is an important factor for a wind developer.
- *Bird and bat impacts* – There has been much concern about the impacts of wind turbines on birds and bats. According to the American Wind Association website, "Birds occasionally collide with wind turbines, as they do with other tall structures such as buildings. Avian deaths have become a concern at Altamont Pass in California, which is an area of extensive wind development and also high year-round raptor use. Detailed studies, and monitoring following construction, at other wind development areas indicate that this is a site-specific issue that will not be a problem at most potential wind sites.

The AWEA website offers extensive information about wind energy. (www.awea.org/faq/).

8.c. To test a particular site's actual wind resources, the best course is to install wind monitoring equipment (including an anemometer and data logging equipment) on a tower at an appropriate height and gather data on wind speed for 12 months. The height of the test tower depends on the size turbine being studied and can range from 20 meters for a residential wind turbine to much higher for utility-scale projects. Data logging equipment is used and the data analyzed to determine the suitability of the site's wind resources for energy production. Green Energy Ohio is a non-profit organization that loans wind monitoring equipment to people and businesses in Ohio for testing their local wind resources (see http://www.greenenergyohio.org/page.cfm?pageID=578).

9. Refer to the McDonald Testimony at page 7. Mr. McDonald stated that wind projects could be developed in other states, as many other utilities have done.

a. Identify the utilities that have a retail service area and have developed wind projects in states that do not encompass any of their service territory. For each such utility, identify the site of each out-of-state wind project.

b. If East Kentucky Power Cooperative, Inc. were to develop such wind projects outsde of Kentucky, what steps would it have to take to deliver that power to its member cooperatives.

RESPONSE:

I have not had sufficient time to research this question completely. Following are two examples and I would be happy to provide more examples if I may provide this information at a later date.

Appalachian Power – In 2007 AEP subsidiary Appalachian Power signed a power purchase agreement for 75MW of wind energy from Camp Grove Wind Farm, LLC near Camp Grove, Illinois. As of September 2007, the PPA was subject to approval from the West Virginia Public Service Commission, implying that the power was to be sold to West Virginia customers, albeit being produced in Illinois. I do not know if AEP operates in Illinois, but I believe Appalachian Power does not operate in Illinois. (Source: Wind Energy Weekly, AWEA, Vol. 26 #1259, 28 September 2007)

Los Angeles Department of Water and Power – 20 year PPA for UPC Wind to supply Los Angeles, via the Southern California Public Power Authority, with wind power from UPC's Milford Wind Corridor Project in Utah. LADWP will receive 185 MW from Phase I of the Milford facility; Burbank will receive 10 MW from the project, and Pasadena 5 MW. The wind project will be in Millard and Beaver Counties, Utah. (Source: Wind Energy Weekly, American Wind Energy Association, Vol. 26, #1270, 21 December 2007.)

9.b. If EKPC wanted to develop wind capacity outside of Kentucky, they could approach the issue in a couple ways. They could:

a. Identify regions outside the state through which EKPC could transmit power.

b. Identify who EKPC would need to work with in order to utilize those transmission lines and determine what sorts of contractual agreements would be required.

c. Research potentially viable wind sites in those regions; or find companies that are already developing wind projects and investigate entering agreements with them for their planned projects.

Alternately, EKPC could issue an RFP for a certain amount of wind power, and specify in the RFP that the bidders are responsible for bringing the power to EKPC's transmission system. Eon issued an RFP in 2007 for renewable energy and included a provision like this. In this way, the prospective wind developers, regardless of where they are located, would have to do the legwork to figure out how to get the power into EKPC's system. The best course for EKPC might be to perform their own research as outlined in steps a, b, and c, while also issuing an RFP. EKPC would have the option of purchasing the wind energy from a third party or owning the wind farm themselves.

One of the most helpful things EKPC could do from the start might be to contract a consultant experienced with developing utility-scale wind projects to assist them with the process. They might also contact Scott Sykes of Genesis Developments in Pikeville, who is currently seeking to develop wind projects in Eastern Kentucky. They could also contact TVA, which has wind energy projects in Tennessee. A conversation with them might be helpful.

10. Refer to page 8 of the McDonald Testimony, specifically the quote on lines 9-17 and the footnotes to the quote.

a. Provide the work product/report/document provided by Soft Energy Associated which, according to footnote 4, was relied upon to develop the information preceding the last sentence in the quote.

b. Refer to footnote 5. Explain why the hydroelectic generating plants of Georgia Power were selected to form the basis for the statment contained in the last sentence in the quote.

RESPONSE:

10. a. Table 4-A in Exhibit 6, "A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative," provides detailed information from Soft Energy Associates that forms the basis of this quotation. In an email dated March 19, 2008, David Brown-Kinloch of Soft Energy Associates wrote to me:

> "The chart was based on site visits, work on FERC Preliminary Permits (including equipment sizing for particular sites), FERC Licenses held by other parties, and experience at the Lock 7 plant. In particular, we have made site visits to the majority of sites on our list, and have head and flow data on most of the site from U.S.G.S. and Corps of Engineers documents. The size figures are much smaller (and much or realistic based on our experience) that previous high level recon studies of these 39 sites in the early 1980s. If they want additional information, I can provide the 1980s recon studies. "
>
> " In general, we based the Kentucky River figures on specific calculations done of some of the sites, based on adding turbines in the abandoned lock chambers. While using the lock chambers lowers the development costs, it also limits the size of the development. The same is true of the sites on the Green and Barren Rivers that have abandoned navigational dams (we had FERC Preliminary Permits on three of these sites and did extensive work on them). The Corps

flood control reservoirs are based our FERC Preliminary Permits at Taylorsville Lake, Green River Lake and Cave Run Lake. We did 7 years of work on a development at Taylorsville Lake. The Ohio River site information comes from doing extensive work for the party that held the FERC Licenses for Cannelton, Smithland and Meldahl Lock and Dams. I have boxes of information on many of the sites listed above."

10.b. I do not know the answer to this question. I have asked the author of the statement (Susan Zinga) to explain this and will provide an answer to the PSC as soon as I have it.

11. Refer to the table of page 16 of the McDonald Testimony. Provide a detailed description of the assumptions used to develop the generation costs shown in the table.

RESPONSE:

Explanation of costs per kWh for renewable energy technologies.

Solar PV

Average installed cost per kilowatt	\$8,000 - \$10,000/ watt
Annual Generation per installed kW	1,200 kWh/kW
Operational Life	30 years
Lifecycle energy generation per kW	36,000 kWh
Lifecycle cost per kW, low range	(\$8,000/36,000 kWh) = \$0.222/kWh
Lifecycle cost per kW, high range	(\$10,000/36,000 kWh) = \$0.278/kWh

The average installed cost per kilowatt is typical for PV installations in Kentucky at this time and I expect these prices to come down in the years to come, especially if major investments such as those I proposed were to be made in PV in the state. The electricity production estimated for the PV systems in this analysis is based upon Kentucky's average annual solar radiation of 4.5 kWh/m^2/day and includes a derate factor of 0.77 to account for efficiency losses. The average expected electricity production for PV systems in Kentucky is 1,198 kWh/kW (that is, a PV system rated at 1 kW (DC current) and located at a site with full sun, facing south, and mounted at a fixed tilt of 38°, will generate 1,198 kWh in a normal year.) The electricity production from a grid-connected PV array at many locations in the US and around the world can be quickly calculated by NREL's PV Watts program, available for free at http://rredc.nrel.gov/solar/codes_algs/PVWATTS/.

PV panels are usually warranted for 20 or 25 years and are expected to operate for 40 years or more.

Solar Water Heating

Exhibit 10 provides the spreadsheets used to calculate the cost of solar water heater (SWH) energy generation. This spreadsheet was used for the report, "A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative," which I co-authored with Susan Zinga. There are two sheets in the file, one for a Commercial SWH Program and one for a Residential SWH program. This spreadsheet describes an incentive program in which EKPC would provide a one-time incentive of \$0.45 per annual kWh savings from the

SWH (based on an estimate of the unit's first year energy savings). Cell M8 on each sheet shows the total cost per kWh for the entire program, which includes annual administrative expenses and EKPC incremental program expenses. This is the figure used as the "Cost per kWh" in my testimony.

However, if we were to exclude the EKPC rebate and its administrative costs, but retain the Federal Tax Credit, the cost per kWh saved over the life of the SWH (25 years) works out to $0.068/kWh for residential systems and for commercial systems it is $0.047/kWh.

Table 2 – Residential Solar Water Heater Cost per Kwh
Initial Installed Cost$4,500
O&M over 25 years$1,000
Federal Tax Credit- $1,350
Lifecycle cost to owner$4,150
Lifecycle Energy Savings61,325 kWh
Lifecycle cost per kWh$0.068

Table 3 - Commercial Solar Water Heater Cost per Kwh
Initial Installed Cost$24,000
O&M over 25 years$3,600
Federal Tax Credit- $7,200
Lifecycle cost to owner$20,400
Lifecycle Energy Savings436,400
Lifecycle cost per kWh$0.047

Hydro-electric Power

The figures used in my testimony were drawn from Table A-5 in the Appendix of "A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative," which is provided as Exhibit 6. I have requested a description of the methods used by Soft Energy Associates to calculate these costs but have been unable to acquire them by the March 20, 2008 deadline. When I receive them I will forward them to the PSC.

Wind Energy

The figures used in my testimony were drawn from "A Portfolio of Energy Efficiency and Renewable Energy Options for East Kentucky Power Cooperative." Although I was co-author on this report, I did not write the section on wind and do not have the background data used there. I have asked Susan Zinga to provide a description of how she calculated the cost per kWh for wind energy and I will forward that to the PSC as soon as possible.

12. Refer to pate 19 of the McDonald Testimony. Explain whether the cap on total installed capacity or PV system size has been binding on any specific development in Kentucky.

RESPONSE:

The cap on total installed capacity of net-metered PV systems has not inhibited any solar PV developments in Kentucky as of this date, to the best of my knowledge. However, if the state were to decide to make substantial investments in solar energy (or other renewables, if the net metering law gets broadened as I believe it should), then we could foresee the day when our efforts to expand our renewable energy capacity might come up against this limit to installed net-metered capacity.

The Interstate Renewable Energy Council has published a "Guide to Distributed Generation Interconnection Issues," and they recommend providing no limits for the total capacity of net metered systems allowed in a service area. I believe this is a matter of principle, in the spirit of removing unnecessary barriers to something which is recognized as being socially beneficial (renewable energy). As I stated in my original testimony, if there are technical reasons why distributed generation sources should not exceed a certain percentage of a utility's peak demand, then such a limit should be respected. In the absence of a technical justification for imposing a limit, the limit appears to be simply a means for restricting the growth of renewable energy. (*Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues*, 5th Edition, 2007, Interstate Renewable Energy Council and the North Carolina Solar Center.)

13. Refer to pages 20-21 of the McDonald Testimony regarding solar set-asides. Provide detailed descriptions of the specific solar set-asidep programs of the 5 states identified in the testimony.

RESPONSE:

The following descriptions of the solar set aside programs of these states are excerpted from the Database of State Incentives for Renewable Energy (www.dsireuse.org). If you visit this website, you can find information for each state by clicking on the map and then scrolling through the list of various policies and incentives.

North Carolina

North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), enacted in August 2007, requires all investor-owned utilities in the state to supply 12.5% of 2020 retail electricity sales (in North Carolina) from eligible energy resources by 2021. Municipal utilities and electric cooperatives must meet a target of 10% renewables by 2018 and are subject to slightly different rules. In February 2008, the North Carolina Utilities Commission (NCUC) adopted final rules implementing the REPS.

Eligible energy resources include solar-electric (photovoltaics), solar thermal, wind, hydropower up to 10 megawatts (MW), ocean current or wave energy, biomass* that uses Best Available Control Technology (BACT) for air emissions, landfill gas, waste heat from renewables, and hydrogen derived from renewables. Up to 25% of the requirements may be met through energy efficiency technologies, including combined heat-and-power (CHP) systems powered by non-renewable fuels. After 2018, up to 40% of the standard may be met through energy efficiency.

The overall target for renewable energy includes technology-specific targets of 0.2% solar by 2018 (which includes photovoltaics, solar water heating, solar absorption cooling, solar dehumidification, solar thermally driven refrigeration, and solar industrial process heat), 0.2% energy recovery from swine waste by 2018, and 900,000 megawatt-hours (MWh) of electricity derived from poultry waste by 2014. The NCUC has required that each electric power supplier submit its first annual REPS compliance plan by September 1, 2008. Beginning in 2009, each power supplier will be required to file a compliance report, detailing the actions it has taken to fulfill the requirements of the REPS.

The compliance schedule for investor-owned utilities appears below. Note that each year's percentage requirement refers to the previous year's electricity sales (i.e. the 2021 goal is 12.5% of 2020 retail sales).

- 2010: 0.02% from solar
- 2012: 3% (including 0.07% from solar + 0.07% from swine waste + 170,000 MWh from poultry waste)
- 2013: 3% (including 0.07% from solar + 0.07% from swine waste + 700,000 MWh from poultry waste
- 2014: 3% (including 0.07% from solar + 0.07% from swine waste + 900,000 MWh from poultry waste)
- 2015: 6% (including 0.14% from solar + 0.14% from swine waste + 900,000 MWh from poultry waste)
- 2018: 10% (including 0.20% from solar + 0.20% from swine waste + 900,000 MWh from poultry waste)
- 2021: 12.5% (including 0.20% from solar + 0.20% from swine waste + 900,000 MWh from poultry waste)

Electric cooperatives and municipal utilities must meet the solar, swine waste and poultry waste goals, but these utilities only must meet an overall target of 10% by 2018. Unlike investor-owned utilities, cooperatives and municipal utilities are permitted to use demand side management (in addition to energy efficiency) to satisfy up to 25% of the standard, and may also use large hydropower to meet up to 30% of the standard.

Utilities demonstrate compliance by procuring renewable energy credits (RECs) earned after January 1, 2008. Under NCUC rules, a REC is equivalent to 1 MWh of renewable energy generation, but the law explicitly states that RECs do not include credit for emissions reductions from oxides of sulfur and nitrogen, mercury or carbon dioxide. Excess RECs may be applied to the next year's compliance target. Utilities may use unbundled RECs from out-of-state renewable energy facilities to meet up to 25% of the portfolio standard. Qualifying out-of-state facilities are (1) hydroelectric power facilities with a generation capacity up to 10 MW, or (2) renewable energy facilities placed into service on or after January 1, 2007. Suppliers with fewer than 150,000 customers are not limited in the amount of out-of-state renewable energy RECs they may procure to meet the standard. In its February 2008 rules, the NCUC decided to pursue a third-party tracking system to track the creation, ownership and retirement of RECs. However, the NCUC declined to develop or require participation in a REC-trading platform.

Utilities may recover the incremental cost of renewable resources and up to $1 million in alternative energy research expenditures annually from customers. The cost per customer account is capped according to the following schedule:

	2008	2012	2015
Residential	$10	$12	$34
Commercial	$50	$150	$150
Industrial	$500	$1,000	$1,000

The NCUC is responsible for administering the REPS and may adjust or modify the REPS schedule if the commission deems such modifications to be in the public interest. Under the NCUC's final rules, there are no specified penalties or alternative payments for noncompliance, but the commission has existing authority under Chapter 62 of the N.C. General Statutes to enforce compliance.

**The NCUC decided not to expand the definition of biomass specified in N.C. Gen. Stat. § 62-133.8(a)(8): "agricultural waste, animal waste, wood waste, spent pulping liquors, combustible residues, combustible liquids, combustible gases, energy crops, or landfill methane; or waste heat derived from a renewable energy resource." Further determination of what constitutes a qualifying biomass resource may be made on a case-by-case basis.*

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Maryland

Maryland's Renewable Energy Portfolio Standard, enacted in May 2004 and revised in 2007, requires electricity suppliers (all utilities and competitive retail suppliers) to use renewable energy sources to generate a minimum portion of their retail sales. Beginning in 2006, electricity suppliers are to provide 1% of retail electricity sales in the state from Tier 1* renewables and 2.5% from Tier 2** renewables. The renewables requirement increases gradually, ultimately reaching a level of 9.5% from Tier 1 resources in 2022 and beyond, and 2.5% from Tier 2 resources from 2006 through 2018. The Tier 2 requirement sunsets, dropping to 0% in 2019 and beyond.

Legislation enacted in April 2007 (SB 595) added a provision requiring electricity suppliers to derive 2% of electricity sales from solar energy *in addition to* the 7.5% renewables derived from other Tier 1 resources as outlined in the initial RPS law. The solar set-aside begins at 0.005% of retail sales in 2008 and increases incrementally each year to reach 2% by 2022. The set-aside is projected to result in the development of roughly 1,500 MW of solar capacity by 2022.

Percentage Renewables Required by Year

Year	Solar	Other Tier 1	Tier 2
2006	0	1.0	2.5
2007	0	1.0	2.5
2008	0.005	2.0	2.5
2009	0.01	2.0	2.5
2010	0.025	3.0	2.5
2011	0.04	3.0	2.5
2012	0.06	4.0	2.5
2013	0.1	4.0	2.5
2014	0.15	5.0	2.5
2015	0.25	5.0	2.5
2016	0.35	6.0	2.5
2017	0.55	6.0	2.5

2018	0.9	7.0	2.5
2019	1.2	7.5	0
2020	1.5	7.5	0
2021	1.85	7.5	0
2022+	2.0	7.5	0

Electricity suppliers demonstrate compliance with the standard by accumulating renewable energy credits (RECs) equivalent to the required percentages outlined above. A REC has a three-year life during which it may be transferred, sold, or otherwise redeemed.

Initially, the RPS included credit multipliers for wind, solar, and methane. Although the multiplier for solar was replaced by the 2% solar requirement in 2007, the following multipliers for wind and methane are still in effect for facilities placed in service on or after January 1, 2004:

- A supplier receives 120% credit toward meeting its Tier 1 obligations through RECs associated with wind energy through December 31, 2005. Beginning in 2006 and through 2008, a 110% credit is in effect.

- A supplier receives 110% credit toward meeting its Tier 1 obligations through RECs associated with energy derived from methane through 2008.

Energy from Tier 1 resources is eligible for RPS compliance regardless of when the system or facility was placed in service and may be applied to either Tier 1 or Tier 2 obligations. However, electricity suppliers may begin to receive or accumulate RECs on or after January 1, 2004. Special conditions apply for Tier 1 hydroelectric resources and Tier 2 resources regarding dates of eligibility.

Solar resources must be connected with the distribution grid serving Maryland, except that on or before December 31, 2011, solar resources not connected to the Maryland grid are eligible only if offers for solar RECs from Maryland grid sources are not made to an electricity supplier that would satisfy the RPS.

Provisions specific to the solar set-aside include the following:

- If the owner of a solar generating system chooses to sell RECs, the owner must first offer the RECs for sale to an electricity supplier for RPS compliance;

- Electricity suppliers purchasing RECs directly from a solar energy system owner must enter into a contract for at least 15 years;

- The parties are free to negotiate a price for solar RECs that varies over time;
- Electricity suppliers purchasing RECs from solar systems with a capacity of 10 kW or less must purchase the RECs with a single upfront payment representing the full estimated projection of the systems for the life of the contract; and
- Maryland's Public Service Commission is charged with developing a method for estimating annual production, determining the REC payment amount, and designating an individual to develop the solar program requirements and outreach activities.

Each electricity supplier must submit a report to the Public Service Commission annually that demonstrates compliance with the RPS. An electricity supplier that fails to meet the standard must pay into the Maryland Renewable Energy Fund at a rate of:

- 2.0¢/kWh for non-solar Tier 1 shortfalls;
- 1.5¢/kWh for Tier 2 shortfalls;
- 45¢/kWh for solar shortfalls in 2008, 40¢/kWh in 2009, and continuing to decline by 5¢ bi-annually until it reaches 5¢/kWh in 2023 and beyond; and
- 0.8¢/kWh for Tier 1 shortfalls for industrial process load in 2006-2008, declining incrementally to 0.2¢/kWh in 2017 and later; no fee for Tier 2 shortfalls for industrial process load.

Compliance fees paid into the Maryland Renewable Energy Fund, which is administered by the Maryland Energy Administration, will be used to make loans and grants to support the creation of new Tier 1 renewable energy sources in the state. Compliance fees for the solar obligation may only be used to support new solar resources in the state.

Electricity suppliers may recover costs incurred to comply with the standard in the form of a generation surcharge on all customers. However, the RPS law provides compliance cost caps and provisions for delaying compliance with the solar set-aside. If the actual or projected dollar-for-dollar cost for purchasing solar RECs in any one year is greater than or equal to 1% of the electric supplier's total annual electricity sales revenues in Maryland, the electricity supplier may request that the PSC to delay by 1 year each of the scheduled percentages for solar and allow the solar percentage required for that year to continue to apply to the electricity supplier for the following year. The delay will continue each year until the actual or anticipated cost is less than 1% of the supplier's annual sales revenue in Maryland, at which time the supplier will be subject to the next scheduled percentage increase.

** Tier 1 resources include solar, wind, qualifying biomass (excluding sawdust), methane from the anaerobic decomposition of organic materials in a landfill or wastewater treatment plant, geothermal, ocean (including energy from waves, tides, currents and* *thermal differences), fuel cells powered by methane or biomass, and small hydroelectric plants (systems less than 30 megawatts in capacity and in operation as of January 1, 2004).*

*** Tier 2 sources include hydroelectric power other than pump-storage generation, waste-to-energy facilities, and poultry-litter incineration.*

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Delaware

In 2005, Senate Bill 74 established a renewable portfolio standard (RPS) requiring retail electricity suppliers to purchase 10% of the electricity sold in the state from renewable sources by 2019. Senate Bill 19 of 2007 increased the RPS target to 20%, of which 2% must come from solar photovoltaics (PV). The RPS applies to the state's investor owned utilities, municipal utilities, and rural electric cooperatives. Municipal utilites and rural electric cooperatives were allowed to opt out of the RPS requirements if they established a voluntary green power program and created a green energy fund, and all cooperative and municipal utilities have opted out. Sales to industrial customers with a peak load of more than 1,500 kilowatts (kW) are exempt from the standard's requirements.

Eligible renewable-energy technologies include solar electric, solar heating and cooling that offsets electricity, wind, ocean tidal, ocean thermal, fuel cells powered by renewable fuels, hydroelectric facilities with a maximum capacity of 30 megawatts (MW), sustainable biomass, anaerobic digestion, and landfill gas.

The RPS compliance schedule is as follows. It should be noted that the PV target is not in addition to the main target, it is included within it:

- **On and after 6/1/07:** 1%
- **On and after 6/1/08:** 1.5% (0.011% PV)
- **On and after 6/1/09:** 2.0% (0.014% PV)
- **On and after 6/1/10:** 5.0% (0.018% PV)
- **On and after 6/1/11:** 7.0% (0.048% PV)
- **On and after 6/1/12:** 8.5% (0.099% PV)
- **On and after 6/1/13:** 10% (0.201% PV)

- **On and after 6/1/14:** 11.5% (0.354% PV)
- **On and after 6/1/15:** 13% (0.559% PV)
- **On and after 6/1/16:** 14.5% (0.803% PV)
- **On and after 6/1/17:** 16% (1.112% PV)
- **On and after 6/1/18:** 18% (1.547% PV)
- **On and after 6/1/19:** 20% (2.005% PV)

Beginning in compliance year 2010, and in each year afterward, the PSC may review the schedule and recommend that the state legislature accelerate or decelerate the schedule as necessary. Beginning in compliance year 2014, and in each year afterward, the PSC itself may accelerate or decelerate the schedule given certain market conditions.

For all suppliers, no more than 1% of each year's total retail sales may be met by eligible renewable resources placed into service on or before December 31, 1997. In compliance year 2020 and each year afterward, all eligible renewable resources used to meet the standard must be placed into service after December 31, 1997.

Energy sold or displaced by a customer-sited eligible energy resource can generate renewable energy credits for RPS compliance, provided the system is sited in Delaware. The output from generators under 100 kilowatts may be aggregated for RPS compliance.
The PSC will certify generation units as "eligible energy resources". Certified generators are entitled to a renewable energy credit (REC) for each megawatt-hour (MWh) of energy they generate. Delaware RECs are tracked by the PJM-EIS Generation Attributes Tracking System (GATS).

Suppliers must submit report an annual report detailing their compliance status. Suppliers who fail to comply with the standard's requirements must pay into the Delaware Green Energy Fund an alternative compliance payment (ACP) of $25 per MWh of shortfall. The ACP increases in subsequent years for suppliers who elect to pay it. After the first year that suppliers pay the ACP, the ACP increases to $50 per MWh. After the second year, it increases to $80 per MWh. The solar ACP begins at $250 per MWh and increases to $300 if the electricity supplier has opted for the ACP in any previous year. The ACP then increases to $350 with subsequent uses. The Delaware Energy Office has the authority to review and adjust the ACP and solar ACP given certain market conditions.

Suppliers will receive 300% credit toward RPS compliance for energy generated by in-state PV and fuel cells using renewable fuels. Suppliers will receive 150% credit toward RPS compliance for energy generated by wind turbines sited in Delaware on or before December 31, 2012.

Suppliers may recover actual dollar-for dollar costs of RPS compliance -- with a conditional exception of alternative-compliance payments -- through a non-bypassable surcharge on customer bills.

In Order No. 6931 dated June 6, 2006, the PSC adopted and approved the Rules and Procedures to Implement the original Renewable Energy Portfolio Standard. Proposed revisions to these rules consistent with the amended statute were issued for comment under Order No. 7276 in September 2007.

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Pennsylvania

Pennsylvania's Alternative Energy Portfolio Standard (AEPS) (SB 1030), enacted November 30, 2004, requires each electric distribution company and electric generation supplier to retail electric customers in Pennsylvania to supply 18% of its electricity using alternative-energy resources by 2020.* Pennsylvania's standard provides for a solar set-aside, mandating a certain percentage of electricity generated by photovoltaics (PV). Pennsylvania's AEPS also includes demand-side management, waste coal, coal-mine methane and coal gasification as eligible technologies.

The law established two categories of energy sources. The standard calls for utilities to generate 8% of their electricity by using "Tier I" energy sources and 10% using "Tier II" sources by May 31, 2021. Eligible resources may originate within Pennsylvania or within the PJM regional transmission organization (RTO).

Tier I sources include (new and existing) photovoltaic energy, solar-thermal energy, wind, low-impact hydro, geothermal, biomass, biologically-derived methane gas, coal-mine methane and fuel cells.

Tier II sources include (new and existing) waste coal, distributed generation (DG) systems, demand-side management, large-scale hydro, municipal solid waste, wood pulping and manufacturing byproducts, and integrated gasification combined cycle (IGCC) coal technology. (See 73 P.S. § 1648.2 for detailed definitions of eligible alternative-energy sources.)

The PUC has adopted the following 15-year compliance schedule to implement Pennsylvania's AEPS:

- **06/01/06 - 05/31/07: Tier I (including solar) - 1.5%; Tier II - 4.2%; Solar PV - 0.0013%**

- **06/01/07 - 05/31/08: Tier I (including solar) - 1.5%; Tier II - 4.2%; Solar PV - 0.0030%**
- **06/01/08 - 05/31/09: Tier I (including solar) - 2.0%; Tier II - 4.2%; Solar PV - 0.0063%**
- **06/01/09 - 05/31/10: Tier I (including solar) - 2.5%; Tier II - 4.2%; Solar PV - 0.0120%**
- **06/01/10 - 05/31/11: Tier I (including solar) - 3.0%; Tier II - 6.2%; Solar PV - 0.0203%**
- **06/01/11 - 05/31/12: Tier I (including solar) - 3.5%; Tier II - 6.2%; Solar PV - 0.0325%**
- **06/01/12 - 05/31/13: Tier I (including solar) - 4.0%; Tier II - 6.2%; Solar PV - 0.0510%**
- **06/01/13 - 05/31/14: Tier I (including solar) - 4.5%; Tier II - 6.2%; Solar PV - 0.0840%**
- **06/01/14 - 05/31/15: Tier I (including solar) - 5.0%; Tier II - 6.2%; Solar PV - 0.1440%**
- **06/01/15 - 05/31/16: Tier I (including solar) - 5.5%; Tier II - 8.2%; Solar PV - 0.2500%**
- **06/01/16 - 05/31/17: Tier I (including solar) - 6.0%; Tier II - 8.2%; Solar PV - 0.2933%**
- **06/01/17 - 05/31/18: Tier I (including solar) - 6.5%; Tier II - 8.2%; Solar PV - 0.3400%**
- **06/01/18 - 05/31/19: Tier I (including solar) - 7.0%; Tier II - 8.2%; Solar PV - 0.3900%**
- **06/01/19 - 05/31/20: Tier I (including solar) - 7.5%; Tier II - 8.2%; Solar PV - 0.4433%**
- **06/01/20 - 05/31/21: Tier I (including solar) - 8.0%; Tier II - 10%; Solar PV - 0.5000%**

The law established an alternative compliance payment (ACP) of $45 per megawatt-hour; however, a separate ACP for solar PV has been set at "200% of average market value" of the solar credits sold during the reporting period. Compliance is based on renewable energy credits, and banking of excess credits will be allowed for up to two years. A credit is equal to a megawatt-hour of renewable generation and credits are the property of the renewable energy generator. Renewable energy credits are tracked by the PJM GATS system. Monies received through the ACP will be transferred into Pennsylvania's Sustainable Energy Funds and used solely to support alternative-energy projects.

The PUC has determined that electric distribution companies may fully recover "the reasonable and prudently incurred costs of complying" with the AEPS. These include the costs for purchases of alternative energy or alternative energy credits, payments to credit program administrators, and costs levied by RTOs to ensure that alternative resources are reliable. Recoverable costs generally do not include ACPs. The costs will be recovered through an automatic adjustment and are considered to be a cost of generation supply. Electric generation suppliers have not been granted cost recovery by the PUC.

The AEPS contains a force majeure clause under which the Commission can make a determination as to whether there are sufficient alternative energy resources in the market for utilities to meet their targets. If the Commission determines that utilities are unable to comply with the standard despite good faith efforts, the Commission may alter the obligation for a given year. The Commission may then require higher obligations in subsequent years to compensate for shortfalls.

Background
House Bill 1203 of 2007 provided a more detailed solar schedule, clarified the force majeure clause, confirmed REC property rights for generators, added solar thermal to Tier I, clarified that AEPS RECs cannot have been retired for other purposes, and expanded the definition of customer-generator.

** Pennsylvania's rural electric cooperatives must offer retail customers a voluntary program of energy efficiency and demand-side management programs to satisfy compliance with the AEPS.*

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New Jersey

New Jersey's renewable portfolio standard (RPS) -- one of the most aggressive in the United States -- requires each supplier/provider serving retail customers in the state to include in the electricity it sells 22.5% qualifying renewables by 2021. The New Jersey Board of Public Utilities (BPU) made extensive revisions to the RPS in April

2006, significantly increasing the required percentages of "Class I" and "Class II" renewable energy, as well as the required separate percentage of solar electricity. By reporting year 2021, 2.12% solar electricity is required.

"Class I" renewable energy is defined as electricity derived from solar energy, wind energy, wave or tidal action, geothermal energy, landfill gas, anaerobic digestion, fuel cells using renewable fuels, and -- with written permission of the New Jersey Department of Environmental Protection (DEP) -- certain other forms of sustainable biomass. "Class II" renewable energy is defined as electricity generated by hydropower facilities no greater than 30 megawatts (MW), and resource-recovery facilities approved by the DEP and located in New Jersey. Electricity generated by a resource-recovery facility outside New Jersey qualifies as "Class II" renewable energy if the facility is located in a state with retail electric competition and the facility is approved by the DEP.

The required percentages of each category and the total renewables percentage required are listed below, by reporting year:

- 6/1/04 - 5/31/05: Solar – 0.0100%; Class I – 0.740%; Class II – 2.5%; Total – 3.2500%
- 6/1/05 - 5/31/06: Solar -- 0.0170%; Class I – 0.983%; Class II – 2.5%; Total – 3.5%
- 6/1/06 - 5/31/07: Solar – 0.0393%; Class I – 2.037%; Class II – 2.5%; Total – 4.5763%
- 6/1/07 - 5/31/08: Solar – 0.0817%; Class I – 2.924%; Class II – 2.5%; Total – 5.5057%
- 6/1/08 - 5/31/09: Solar – 0.1600%; Class I – 3.840%; Class II – 2.5%; Total – 6.500%
- 6/1/09 - 5/31/10: Solar – 0.2210%; Class I – 4.685%; Class II – 2.5%; Total – 7.406%
- 6/1/10 - 5/31/11: Solar – 0.3050%; Class I – 5.492%; Class II – 2.5%; Total – 8.297%
- 6/1/11 - 5/31/12: Solar – 0.3940%; Class I – 6.320%; Class II – 2.5%; Total – 9.214%
- 6/1/12 - 5/31/13: Solar – 0.4970%; Class I – 7.143%; Class II – 2.5%; Total – 10.14%
- 6/1/13 - 5/31/14: Solar – 0.6210%; Class I – 7.977%; Class II – 2.5%; Total – 11.098%
- 6/1/14 - 5/31/15: Solar – 0.7650%; Class I – 8.807%; Class II – 2.5%; Total – 12.072%
- 6/1/15 - 5/31/16: Solar – 0.9280%; Class I – 9.649%; Class II – 2.5%; Total – 13.077%
- 6/1/16 - 5/31/17: Solar – 1.1180%; Class I – 10.485%; Class II – 2.5%; Total – 14.103%
- 6/1/17 - 5/31/18: Solar – 1.3330%; Class I – 12.325%; Class II – 2.5%; Total – 16.158%
- 6/1/18 - 5/31/19: Solar – 1.5720%; Class I – 14.175%; Class II – 2.5%; Total – 18.247%

- 6/1/19 - 5/31/20: Solar – 1.8360%; Class I – 16.029%; Class II – 2.5%; Total – 20.365%
- 6/1/20 - 5/31/21: Solar – 2.1200%; Class I – 17.880%; Class II – 2.5%; Total – 22.5%

The BPU will adopt rules to determine the minimum percentages for reporting year 2022 and beyond. These minimum percentages will be equal to or greater than the minimum percentages required for reporting year 2021.

Additional solar electricity may be used to fulfill any of the three required categories, while additional "Class I" electricity may be used to fulfill the "Class II" requirement. To qualify as "Class I" or "Class II" renewable energy, electricity must be generated within or delivered into the PJM region. "Class I" or "Class II" renewable energy delivered into the PJM region must be generated at a facility that began construction on or after January 1, 2003, in order to qualify.

Suppliers/providers may meet these requirements by submitting "Class I" renewable-energy certificates (Class I RECs), "Class II" RECs and Solar RECs, all of which represent the environmental attributes of one megawatt-hour (MWh) of generation from an eligible facility. All RPS compliance must be submitted in the form of RECs, which will be issued either by the BPU or PJM-Environmental Information Services (EIS), through PJM's Generation Attribute Tracking System (GATS). The BPU will issue Solar RECs and "Class I" RECs associated with electricity generated at a customer-generator's premises. Other "Class I" RECs will be issued by PJM-EIS, through GATS. Suppliers/providers may not use RECs associated with electricity generated at a customer-generator's premises unless the facility is eligible for net metering. RECs submitted for RPS compliance will be permanently retired.

If a supplier/provider is not in compliance for a reporting year, the supplier/provider must remit an alternative compliance payment (ACP) and/or a solar alternative compliance payment (SACP) for the amount of RECs and solar RECs that were required but not submitted. The BPU will determine prices for ACPs and SACPs, and will review the prices at least once per year. The price of an ACP and an SCP will be higher than the estimated competitive market cost of (1) the cost of meeting the requirement by purchasing a REC or solar REC, or (2) the cost of meeting the requirement by generating the required renewable energy. Revenue generated by the ACP will be used to fund renewable-energy projects through the New Jersey Clean Energy Program. Revenue generated by the SACP will be used to fund solar projects under the program.

Each supplier/provider is required to file an annual report with the BPU by September 1, demonstrating that the requirements for the preceding reporting year (ending May 31 of the same calendar year) have been met. Failure to comply with any provision of the RPS may result in suspension of the supplier's license, financial penalties, disallowance of recovery of costs in rates, and/or prohibition on accepting new customers.

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14. Refer to the McDonald Testimony, page 21, lines 9-12. Provide a list which identifies the 19 states that have Public Benefits Funds and indicate for each state: the amount of the charge per customer; the total amount collected annually; the percent of the funds used for renewables and energy efficiency programs; and any other purposes for which the funds can be used.

RESPONSE:
The Sierra Club requests additional time to answer this question.

15. Refer to page 1 of the Direct Testimony of Richard M. Clewett, Jr. ("Clewett Testimony"). Provide Mr. Clewett's background, work experience, etc. For the time between the end of his education in 1970 and the apparent beginning of his work with the Sierra Club in 2006.

RESPONSE:
Mr. Clewett's background, work history, etc. between time of finishing school and beginning of his work on energy with the Sierra Club in 2006:

In the fall of 1969, I joined the English Department of Eastern Kentucky University. I have worked there ever since, first as an Assistant Professor, then as an Associate Profess, and most recently as a full Professor. In 1992-93, I was Acting Chair of the Department of Foreign Languages. From 1999-2003, I was the coordinator for the English Department's M.A. program. In May I will finish a three-year half-time transition to retirement program, after which I will have the titled Professor Emeritus.

16. Refer to pages 4-5 of the Clewett Testimony concerning the provision in KRS 278.285 which permits energy intesive industrial customers to 'opt out" of utility-sponsored demand-side management programs. The discussion refers to the 2007 report of the Kentucky Pollution Prevention Center, which indicates that a substantial portion of the energy savings that could be realized under the minially aggressive scenario would come from the industrial sector. The last sentence in this section of the testimony states, "A

revision of the stature [sic] ma well be required to accomplish this end." Provide the language proposed by the Sierra Club to amend or revise that provision of KRS 278.285.

RESPONSE:

We are generally sympathetic to the ideas presented in Theodore Schultz's testimony in the present case concerning improvements that should be made in this statue. Specifically, regarding the current ability of large industrial customers to opt out of utility-run DSM programs, Mr. Schultz said:

All major customer classes should participate in and pay for all conservation and demand response programs. Consistent with KRS 278.285 (1) (k), measurable and verifiable energy and demand savings should be included as a component of the utility's IRP because effective energy efficiency measures reduce the need to build more generation or buy more power benefiting all customers.

Although DE-Kentucky believes that all customers benefit from all energy efficiency programs, the Company does not necessarily oppose an opportunity for the larger commercial and industrial customers, who have undertaken significant conservation initiatives on their own in an effort to reduce their cost of energy, the ability to opt-out of the utility's conservation offerings. In order to opt-out, large commercial and industrial customers should be required to self-certify to the commission that they have undertaken energy efficiency projects or measures at their sites within the last three years.[1]

The Cumberland Sierra Club agrees with Mr. Schultz's proposed change in the statute except that we think that self-reporting is not an adequate mechanism. Also, we would specify that in order to be able to opt out of the utility's conservation program, large users would have to demonstrate that they were achieving energy efficiencies on a level comparable to what they would have achieve had they participated in the utility's energy efficiency program.

17. Refer to the discussion of the studies identified on pages 11-12 of the Clewett Testimony.

a. Explain whether the Sierra Club is aware of any studies of infrastructure development that incorporated both postitive and negative externalities? If yes, identify and describe the studies.

b. Were postive externalities considered in the studies described on pages 11-12 of the testimony? If yes, identify such externalitites.

c. Describe in detail the reasons, if any, why positives externalities should not be considered in such studies.

RESPONSE:

a) studies that incorporate both positive and negative externalities:

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[1] Theodore E. Schultz Direct, p.8, l18-p.9, l. 8

1) **Summary of MDPU's Findings on Environmental Externalities (D.P.U. 89-239)**

- An evaluation system based on project-specific emissions/environmental impacts is preferable to a scoring system that allocates fixed points based on technology types.
- The Massachusetts Institute of Technology Energy Laboratory argued that resource strategies focusing exclusively on improving end-use efficiencies perform poorly in reducing emissions in comparison with resource strategies that balance efficiency improvements in conjunction with supply- and demand-side options. To alleviate these concerns, the MDPU directed electric utilities to optimize ranking of proposals to take into account interactions among resources.
- The MDPU directed that externalities be monetized and that such values be added to direct resource costs when evaluating and comparing alternative energy resources.
- The MDPU concluded that the cost of pollution control estimates that use the implied valuation method to be the best available proxy at the time.121 Accordingly, the MDPU adopted externality values expressed in dollars per ton of emission that were based on the recommendations of Division of Energy Resources estimates.122 Table 3 lists these values and the basis for these estimates. Electric utilities under the jurisdiction of the MDPU were directed to use these values in the IRM process.
- The MDPU permitted electric utilities to submit weights of various categories of project selection criteria for review. As a result of this option, the weight of the combined price/externality category could vary among utilities depending on nonprice criteria.123 The utilities could thus monetize externality values, put them on a consistent basis with price and then allow the relative weights of price/externality and nonprice criteria to vary.124
- The MDPU did not favor including local, site specific impacts in the evaluation process.
- The MDPU directed that priority be placed on estimating environmental externalities that are the direct results of power-plant operations, including all downstream effects, leaving proposals to expand the scope of the regulations to the entire fuel cycle to a later time.
- Although the MDPU took a global view of externalities, it deemed that local job "creation" should ***not*** be counted as a positive externality. In reality, jobs are mostly transfers of individuals moving from one job to another. Granted, not ***all*** jobs are transfer payments, and there may indeed be some social and financial externalities from new employment, but there is insufficient information to generalize.125 Thus, the MDPU took the position that the benefits of "new" employment should be considered on a case-by-case basis.[2]

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[2] Electricity Generation and Environmental Externalities: Case Studies, September 1995, **Energy Information Administration,** Office of Coal, Nuclear, Electric and Alternate Fuels

b) Were positive externalities considered in studies described on pp. 11-12? If so, which ones?
ExternE studies (including the improved methodology put forth in the "New Elements for the Assessment of External Costs from Energy Technologies" document produced in 2004,[3] do not seem to make use of positive externalities. Nor does the Canadian study cited on these pages, which was based on ExternE methodology.

c) There is no theoretical reason why positive externalities should not be considered. If the positive economic development externalities resulting from energy efficiency and renewable energy projects are compared with those resulting from the construction of new coal-fired power plants, coal-to-gas-or-liquid, etc., we feel that energy efficiency and renewable energy will compare favorably to coal, just as a comparison of the negative externalities will favor energy efficiency and renewable energy. The Cumberland Sierra Club has commissioned a study to substantiate this hypothesis.

18. Refer to page 15 of the Clewett Testimony.

a. Provide detailed descriptions of how the institutional practices identified for California, Minnesota and Vermont have been pit into practice in recent planning or siting cases for new generation investment.

b. Explain whether the externalities are included for purposes of investment decision-making only or whether they are also included for rate making decisions.

RESPONSE:

a)

1) The State of California has some of the highest levels of pollution in the country. To alleviate this problem, the State adopted its own Clean Air Act in 1988 to address the unique air quality problems facing the State and to establish procedures to attain ambient air quality standards. The State's environmental regulations address emissions from power plants as well as emissions from other sources like automobiles and industrial facilities.

Coal and Electric Analysis Branch, U.S. Department of Energy: http://www.eia.doe.gov/cneaf/electricity/external/external.pdf.

[3] http://www.ier.uni-stuttgart.de/forschung/projektwebsites/newext/.

In its 1990 report, the California Energy Commission (CEC) directed that all costs and emission impacts of compliance with air quality regulations be accounted for in the analysis of the cost-effectiveness of power generation. The CEC specified externality values for five categories of emissions, which include nitrogen oxide, sulfur dioxide, particulate matter, reactive organic gases, and carbon. These externality values are based on the estimates of the marginal cost of the best available control technology. The values differ regionally depending on a region's air quality and the service area.6

Monetized externality values were used in the State during the resource plannig process in 1993. The CEC noted that externality values have had negligible impact on actual procurement and operations decisions of the utilities. The CEC has subsequently considered marketable permits, environmental performance standards, emission taxes and surcharges, and other methods of evaluating externalities. In the CEC's view, these approaches may permit the "internalization" of externalities. Until this is achieved, its second-best approach is to set standards as interim measures.[4]

2) Vermont

1.4.5 The Societal Test

The Societal Cost Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Cost Test utilizes essentially the same input variables as the TRC test, but they are defined with a broader societal point of view.21 An example of societal benefits is reduced emissions of carbon, nitrous and sulfur dioxide and particulates from electric utility power plants.22 When calculating the Societal Cost Test benefit/cost ratio, future streams of benefits and costs are discounted to the present using a discount rate. The avoided costs of electricity, natural gas, propane, #2 fuel oil, kerosene and water used in this study are provided in Appendix F of this report.

According to the Final Order in Vermont Public Service Board Docket No. 5270, the Societal Test calculation in Vermont includes a 5 percent adder to program electric energy benefits for non-energy benefits (for environmental benefits), and a 10% reduction to costs to account for the risk diversification benefits of energy efficiency measures and programs. The Board subsequently adopted an environmental adder of $.0070 per kWh saved (in $2000). This adder replaces the original 5% adder for environmental externalities. In this report, GDS has used the definition of the Societal Test calculation as specified by the Vermont Pubic Service Board in its final order in Docket No. 5270, and has used the $.0070 adder

[4] op. cit. Electricity Generation and Environmental Externalities. http://www.eia.doe.gov/cneaf/electricity/external/external.pdf

for environmental benefits, adjusted to current year dollars. GDS has also applied the 10% reduction to energy efficiency measure costs for all
20 Ibid., page 33.
21Ibid., page 27.
22 The Vermont Public Service Board Order in Docket No. 5270 cites the following as such societal benefits: reductions in acidic precipitation, carbon dioxide and other greenhouse gases, reduction in habitat destruction, and reduction in nuclear waste disposal risks). Calculations of the Vermont Societal Test. Finally, the VDPS provided GDS with environmental adders relating to fossil fuel savings, and GDS has reflected these adders in the calculation of benefit/cost ratios for the Societal Test.

1.5 Definition of Electric Avoided Costs

The **avoided electric supply costs** for this Vermont energy efficiency potential study consist of the electric supply costs avoided due to the implementation of electric energy efficiency programs. The costs that are avoided depend on the amount electricity that is saved, and when it is saved (in peak heating season periods, seasonal or annual, etc.).

Second, it is very important to note that the electricity avoided costs used in the Total Resource Cost (TRC) Test do not represent the retail rate for each customer class. While the actual retail rate is used in the calculation of the benefits for the Participant Test, the actual retail rate is not the avoided electric cost used in the calculation[5]

b) The description of the policy in California provided on p. 15 clearly suggests that the externalities are used there for purposes of investment decisions. The same seems to be true in Minnesota.

In the European Union, externalities seem to be used for investment decisions and for granting subsidies to renewable energy sources, rather than being included directly in rates.[6]

19. Refer to the Direct Testimony of Richard Shore ("Shore Testimony") at page 9. Mr. Shore states that E. ON and Duke have a financial incentive to operate DSM programs that may look good on paper, but save very little energy in practice.

    a. Identify the programs to which Mr. Shore refers.

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[5] Vermont Electric Energy Efficiency Potential Study
Final Report, *January 2007, pp. 14-15.*
http://publicservice.vermont.gov/energy/vteefinalreportjan07v3andappendices.pdf
http://publicservice.vermont.gov/energy/vteefinalreportjan07v3andappendices.pdf

[6] ExternE: The Definition of External Costs" (last updated 2008): http://www.externe.info/.

b. Does Mr. Shore propose the elimination of the programs identified in (a) above, or can the programs be modified to eliminate his concerns?

RESPONSE:

a. The question misunderstands the assertion. The point of the assertion is the nature of the incentives, not the nature of any particular program. I assert that the current incentive structure favors offering sham programs. The nature of the incentive favors offering programs that will not curtail sales of electricity. The nature of the incentive favors programs that cannot reduce the sale of electricity.

b. It would be nice to review the impact of DSM programs to see which ones are actually reducing the sale of electricity. I suspect that the electric generator firms do that. However, the current incentive program, based as it is on ever increasing sales of electricity, provides a direct financial incentive to avoid any program that stabilizes or decreases electricity sales. It is not modification of programs but modification of incentive system that will eliminate the objection.

20. Refer to the Shore Testimony at pages 7-9. Identify which states currently employ statistical recouping for purposes of dealing with conservation and DSM initiatives.

RESPONSE:

I raised up "statistical recouping" for consideration because it is one of the approaches that has been seriously discussed in the literature of utility rate structures. However, what I tried to state was that "statistical recouping" is, in my opinion, too complex and too obscure to be useful as a regulatory framework. Regulators and the regulated community need clear, transparent procedures for establishing rates. That was why I offered the simple transparent "rider" mechanism, and citated North Carolina as a case in point. The "rider" groups together, as the basis for the rate, costs and proposed electricity savings that have already been reviewed and established by the regulator, together with actual electricity savings that have been verified by an independent third party.

CERTIFICATION OF ACCURACY

I hereby certify that I supervised the preparation of the above Responses and that the information contained in the Responses is true and accurate to the best of the answerer's knowledge, information and belief after reasonable inquiry. I further state that Wallace McMullen supplied the material in answer to questions 1, 2 and 3; that Andrew McDonald answered questions 7, 8, and 9; that Richard Clewett answered questions 15, 16, 17 and 18; and that Richard Shore answered questions 19 and 20.

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CERTIFICATE OF SERVICE

I hereby certify that an original and ten copies of the foregoing Response of Sierra Club to Public Service Commission Staff's First Data Request were mailed to the office of Beth A. O'Donnell, Executive Director of the Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, KY 40601, for filing in the above-styled proceeding and that copies were mailed to the following Parties of Record on this, the 21st day of March, 2008:

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