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PUBLIC SERVICE
COMMISSION

June 27, 2007
29 GMY.

Beth A. O'Donnell
Executive Director
Public Service Commission
PO Box 615
Frankfort, KY 40602-0615

RE: Case No. 2006-00472

Dear Ms. O'Donnell:

Please find enclosed for filing with the Commission in the above-styled proceeding an original and thirteen copies of the Prepared Testimony of the Cumerland Chapter of the Sierra Club. 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

SAS:dek
Enclosure as stated

cc: Parties of record

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WES ADDINGTON
Mine Safety Project Attorney

June 27, 2007

Charles A. Lile, Esq.
Senior Corporate Counsel
East Kentucky Power Cooperative
PO Box 707
Winchester, KY 40392-0707

RE: PSC Case No. 2006-00472

Dear Mr. Lile:

Please find enclosed a copy of the Prepared Testimony of the Cumberland Chapter of the Sierra Club in the above-styled proceeding. A copy of this document has been mailed to all parties listed on the attached Certificate of Service.

Sincerely,

Stephen A. Sanders

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Attorney at Law

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GREG HOWARD
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WES ADDINGTON
Mine Safety Project Attorney

June 27, 2007

Michael L. Kurtz, Esq.
Boehm, Kurtz & Lowry
36 East Seventh St., Suite 1510
Cincinnati, OH 45202-4434

RE: PSC Case No. 2006-00472

Dear Mr. Kurtz:

Please find enclosed a copy of the Prepared Testimony of the Cumberland Chapter of the Sierra Club in the above-styled proceeding. A copy of this document has been mailed to all parties listed on the attached Certificate of Service.

Sincerely,

Stephen A Sanders

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June 27, 2007

Dennis Howard, Esq.
Assistant Attorney General
Office of the Attorney General
Utility & Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601-8204

RE: PSC Case No. 2006-00472

Dear Mr. Howard:

Please find enclosed a copy of the Prepared Testimony of the Cumberland Chapter of the Sierra Club in the above-styled proceeding. 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

SAS:dek
Enclosure as stated

cc: Parties of record

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF: GENERAL ADJUSTMENT OF ELECTRIC RATES OF EAST KENTUCKY POWER COOPERATIVE, INC.	)))	**Case No. 2006-00472**

PREPARED TESTIMONY OF THE CUMBERLAND CHAPTER OF THE SIERRA CLUB

Comes now the Cumberland Chapter of the Sierra Club, ("Sierra Club"), intervenor herein, and submits the following prepared testimony of its witness, Geoffrey M. Young.

Q. Mr. Young, please describe your education and employment experience.

A. I received a bachelor's degree in Economics from the Massachusetts Institute of Technology, a master's degree in Mechanical Engineering from the University of Massachusetts, and a master's degree in Agricultural Economics from the University of Kentucky.

From 2/78 to 8/79, I worked as a Staff Engineer at Technology + Economics, a research consulting firm in Cambridge, Massachusetts. I analyzed the economic and energy savings resulting from energy efficiency technologies and prepared a commercialization plan for a low-cost passive solar heating and cooling system.

From 7/82 to 6/83, I was the Staff Engineer at the Small Business Development Center, administered by the University of Kentucky in Lexington. I performed cost-benefit analyses of energy efficiency and renewable energy technologies, provided technical assistance to small businesses, and maintained and updated a manual with descriptions of energy technologies.

From 4/90 to 9/91, I worked for the Kentucky Division of Waste Management in the Department for Environmental Protection as an Environmental Engineering Technologist Senior. I performed technical and administrative reviews of applications for hazardous waste facility permits. I provided technical assistance to field and enforcement personnel, conducted hazardous waste facility assessments, and provided information to the public.

From 9/91 to 11/94, I worked as an Environmentalist Principal at the Kentucky Division of Energy (KDOE). My major duty at that time was to coordinate the Alternate Energy Development Program. I administered small grants for the demonstration of renewable energy technologies, developed fact sheets and other information for the public, edited a national monthly newsletter on energy efficiency programs in the 50 states, and wrote proposals for grant funding.

I was promoted to assistant director of KDOE in November 1994. In addition to administrative duties and continuing management of the Alternate Energy Development Program, my work focused on demand-side management, energy policy issues, energy-efficient building systems, and alternative fuels for vehicles. Between 1994 and 2004, I represented KDOE on demand-side management collaboratives at Louisville Gas and Electric Company and Kentucky Utilities (E.ON), Kentucky Power Company (AEP), and the Union Light, Heat and Power Company (Duke Energy). I was the lead person for the Division in addressing electric industry regulatory issues before the Commission. KDOE was later reorganized and shifted into the Governor's Office of Energy Policy.

I left State Government in the fall of 2005, and have been working full-time as a volunteer for various nonprofit organizations since then.

Q. Have you participated in other cases before this Commission?

A. Yes. I submitted prepared testimony in the following cases:

- Case No. 98-426, Application of Louisville Gas and Electric Company for Approval of an Alternative Method of Regulation of Its Rates and Service
- Case No. 98-474, Application of Kentucky Utilities Company for Approval of an Alternative Method of Regulation of Its Rates and Service
- Case No. 2000-459, The Joint Application of the Louisville Gas and Electric Company and Kentucky Utilities Company for the Review, Modification and Continuation of DSM Programs and Cost Recovery Mechanisms
- Case No. 2001-053, the Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity, and a Certificate of Environmental Compatibility, for the Construction of a 250 MW Coal-Fired Generating Unit (With a Circulating Fluid Bed Boiler) at the Hugh L. Spurlock Power Station and Related Transmission Facilities, Located in Mason County, Kentucky, to be Constructed Only in the Event that the Kentucky Pioneer Energy Power Purchase Agreement is Terminated
- Administrative Case No. 387, A Review of the Adequacy of Kentucky's Generation Capacity and Transmission System.
- I drafted testimony for KDOE in Administrative Case No. 341, An Investigation Into the Feasibility of Implementing Demand-Side Management Cost Recovery and Incentive Mechanisms.

I was the lead participant and representative for KDOE in the following integrated resource planning cases:

- Kentucky Power Company (dba AEP), Cases No. 99-437 and 2002-00377
- Big Rivers Electric Corporation, Cases No. 99-429 and 2002-00428
- East Kentucky Power Cooperative, Inc., Cases No. 2000-044 and 2003-00051
- Louisville Gas and Electric Company and Kentucky Utilities Company, Cases No. 99-430 and 2002-00367
- The Union Light, Heat and Power Company, Case No. 99-449
- I testified orally at a public hearing and submitted written follow-up comments in Administrative Case No. 2005-00090, An Assessment of Kentucky's Electrical Generation, Transmission, and Distribution Needs.
- I served as an expert witness and submitted prepared testimony in Cases No. 2005-00142 and No. 2005-00467, both of which were styled, Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade and Hardin Counties, Kentucky.
- I drafted extensive public comments on behalf of the Sierra Club that were submitted in Case No. 2006-00564, An Investigation into East Kentucky Power Cooperative, Inc.'s Continued Need for Certificated Generation.

Q. Why is the Sierra Club participating in this proceeding?

A. The Sierra Club requested full intervenor status in this general rate case because over a period of years, we have come to understand that the structure of electric rates can have a major impact on how energy-efficient Kentucky will be. We believe that our interests do not fundamentally conflict with the interests of the general public or any other party to this case, including East Kentucky Power Co-op (EKPC), the Attorney General's Office of Rate Intervention (AG), and the Kentucky Industrial Utilities Customers (KIUC). If we disagree with a particular party from time to time, it is virtually always over means rather than ends. Our intention is to participate fully in these proceedings in a way that enables the Commission to arrive at the best possible decisions, in conformity with its statutory mandate.

We believe that all of the parties, and the Commission itself, would agree with the general proposition that energy waste should be reduced. No one benefits from energy waste. Consequently, eliminating waste by improving the efficiency with which energy services are provided to ultimate customers can offer real economic benefits to all of the parties. The Sierra Club views the energy inefficiency that is currently endemic in all sectors of our economy as a massive, untapped energy resource. If the ratemaking process is designed in the right way, it should be possible for all parties to gain substantial benefits through the operation of a system that encourages all parties to attack and squeeze out energy waste.

It is the Sierra Club's intention to propose innovative yet practical rate structures, policies, and approaches designed to help improve the energy efficiency of Kentucky's electric system. We do not think our proposals will necessarily be devoid of flaws and drawbacks, but we offer them in the hope that the regulatory framework within which utility companies operate will improve over time. Our goal is to help the Commission institute a regulatory system that better aligns the interests of utility companies and their customers. We believe that when all parties work together with the common goal of reducing waste, major energy and economic savings can be achieved.

Q. Does the Sierra Club support EKPC's stated goal of improving its financial solvency over the next several years?

A. Yes. We believe that all of Kentucky's jurisdictional utilities should operate under rate structures that enable them to maintain a reasonable degree of financial strength and that simultaneously create incentives for all parties, including customers, to work together to reduce energy waste. We hold that the utility's most financially advantageous plan should also be the lowest-cost plan for customers and society as a whole.

Q. What is your assessment of EKPC's Wholesale Power Rate Schedule overall?

A. In general, the wholesale tariffs now in effect, as well as the Special Electric Contract Rates with certain large industrial customers, are structured in the traditional manner that has been common to most electric utility tariffs in this country for the past century or so. I say that primarily because there is no mechanism that would decouple EKPC's revenue from the amount of electricity it sells. Another traditional feature is the Fuel Adjustment Clause, which transfers essentially all of the fuel price risk from the utility to its customers.

The absence of decoupling and the presence of the fuel adjustment clause (FAC) have major implications. The most important one is that EKPC has a strong financial incentive to sell more electricity at all times, and has a similarly powerful disincentive to help its ultimate customers improve the efficiency with which they use electricity.

Q. How do these financial incentives arise?

A. In his seminal report, "Profits and Progress through Least-Cost Planning," David Moskovitz described the problem as follows:

1. When rates are fixed (as a result of a rate case), revenues and profits are not fixed. Whenever the marginal revenue from the sale of an additional kWh is higher than the marginal cost of producing that kWh, which is virtually always the case, a utility can increase its net income by selling more electricity.

2. The fuel adjustment clause enables the utility to raise rates, in effect, if the utility is forced to use a higher-priced fuel to meet peak demands. According to Moskovitz,

> "Utilities even make money when they sell power for what initially appears to be less than it costs to produce. For example, to meet increased demand during peak periods, a utility may crank up a relatively inefficient diesel generator that consumes 10 cents worth of fuel to produce one kWh of electricity. The regulated price of power might be seven cents per kWh, which represents five cents in fixed costs and two cents allotted for the utility's 'average' fuel costs. But the utility can recover the extra eight cents in fuel costs later (that is, the generator's ten-cent fuel cost minus the two-cent average fuel cost) by invoking the fuel adjustment clause to raise rates. In effect, the utility charges customers 15 cents for the kWh, 7 cents now and 8 cents later through the true-up provisions of the fuel clause."

3. In general, incremental sales of electricity to an existing customer add no costs other than the fuel needed to produce the power. But because the price of electricity is fixed by the tariff and includes an element designed to allow the utility to recover its fixed costs, each kWh sold adds to net revenue.

4. The same logic applies to reductions in energy consumption. Each kWh not sold, due to customers' energy efficiency improvements or cogenerators, nonutility power producers, etc., has a powerfully negative effect on revenue and net revenue.

[Moskovitz, David, "Profits and Progress through Least-Cost Planning," November, 1989, prepared for the National Association of Regulatory Utility Commissioners (NARUC), pp. 3-6.] The entire report is available on the web at no charge via the website of the Regulatory Assistance Project, where Moskovitz is employed: http://www.raponline.org/Pubs/General/Pandplcp.pdf

Moskovitz' analysis applies quite closely to EKPC's system, because its rate structure is traditional in the essential respects I described above. The more electricity EKPC sells, the more money it makes.

It could be said that this set of financial incentives and disincentives is one of the unintended consequences of the traditional ratemaking approach. Just because certain consequences are unintended or have not been the focus of much recent regulatory attention, however, does not mean they are unimportant. Very often in human affairs, the impacts of the unintended consequences dwarf those of the intended ones.

Q. Is the Sierra Club proposing that the Commission do away with the Fuel Adjustment Clause (FAC)?

A. No. There are other ways to address the unintended consequences that result from the normal operation of the traditional fixed-rate structure combined with the FAC; these alternative strategies will be described in more detail below.

Q. Is David Moskovitz a technical expert in the field that includes the subject of the writings cited above?

A. In order to substantiate the claim that Mr. Moskovitz is a technical expert in this field whose writings may properly be cited in this testimony, I am including the following description of his qualifications:

> David Moskovitz is a Director and co-founder of The Regulatory Assistance Project. He served as a Commissioner of the Maine PUC from 1984 through 1989 after having served as a Commission Staff Attorney for six years. Mr. Moskovitz authored Maine's rules regarding the development of cogeneration and small power production. Prior to joining the Maine PUC, he was employed by Commonwealth Edison, Inc., an Illinois utility. Mr. Moskovitz has published numerous technical and policy articles on incentive regulation, least-cost planning and renewable energy. He is a frequent speaker at national seminars and has provided expert testimony on these topics. He received his B.S.E. in Engineering from Purdue University and his J.D. from Loyola University. (http://www.raponline.org/AboutUs.asp#)

Q. David Moskovitz' report has the word "Profits" in its title. As a cooperative utility that is owned by its customers, doesn't the set of incentives faced by EKPC differ significantly from that of an investor-owned utility (IOU)?

A. Even though EKPC and its member distribution entities are cooperatives that have been incorporated to serve their ultimate customers rather than profit-seeking investors, EKPC is still extremely focused on its net revenues. In the present case, EKPC has expressed the need to raise its net revenue and TIER in order to improve its financial viability during the coming years. It is to be expected that EKPC would be concerned with the health of its bottom line, in the same way that an investor-owned utility would.

During my decade and a half of experience working with utility companies in Kentucky, I have seen no indication that the cooperatives are any less interested in net revenue than the IOUs. In fact, if we use the amount of energy efficiency activity as an approximate indicator, it could be said that in general, the cooperatives in Kentucky are somewhat worse than the IOUs at promoting programs that might reduce sales of electricity, although there is no regulated utility company in Kentucky that has even come close to optimizing the scale, scope, and potential effectiveness of its energy efficiency programs.

Q. David Moskovitz is just one individual. Have other institutions accepted the analysis he developed on this subject?

A. Yes. The basic points of the analysis described in Moskovitz' report of November 1989 were codified in a Resolution in Support of Incentives for Electric Utility Least-Cost Planning that was approved by NARUC's Executive Committee assembled in its 1989 Summer Committee Meeting in San Francisco. The Executive Committee urged its member state public utility commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action.

Q. Was that the end of the story?

A. No. The Federal Energy Policy Act of 1992 (EPAct92) codified this concept in Federal law in the form of a ratemaking standard that each state's public utility commission was required to consider implementing. This standard is now in effect, is codified in 16 USC Chapter 46, subch II, Sec 2611, subsection d(8), and reads as follows:

> (8) Investments in conservation and demand management
> The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission, and distribution equipment. Such energy conservation, energy

> efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

The law was a guideline rather than a requirement; any given public utility commission could choose to implement it in its ratemaking activities or not.

Q. Would you care to comment on the provision in KRS 278.285 that allows certain industrial companies to opt out of participating in utility-assisted DSM programs?

A. Section 3 of KRS 278.285, which includes the industrial opt-out provision, reads as follows:

> (3) The commission shall assign the cost of demand-side management programs only to the class or classes of customers which benefit from the programs. The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

Neither the Commission nor any of the Commonwealth's utility companies has ever defined the meaning of "energy intensive processes" or "cost-effective energy efficiency measures." For example, the claim has been made that any industrial customer whose electric bill is higher than a certain threshold must have an "energy intensive process," even if its energy costs represent only a small percentage of its total costs. The Commission and utility companies have never asked industrial companies to provide any documentation that they have in fact implemented their own cost-effective energy efficiency measures. The result in practice has been that any and all industrial customers have elected to opt out, and they have been permitted to do so. Utility companies (for example, E.ON) then immediately drop any plans to develop DSM programs for the industrial sector. The entire industrial class has consequently been deprived of the opportunity to participate in utility-assisted DSM programs. For a state such as Kentucky, in which the industrial sector accounts for a relatively high percentage of the state's total energy use, this situation is extremely unfortunate.

Q. Would you care to comment on the first sentence in the cited section of KRS 278.285 that, in effect, prohibits a utility from using funds collected from one customer class to invest in DSM programs directed toward another customer class?

A. Yes. In my opinion, that provision is unnecessarily restrictive and tends to reduce the number of cost-effective DSM programs that a utility may operate. Utility companies in other states, for example, have often found that the energy-saving opportunities available in the industrial sector are very large and can be harvested in a highly cost-effective manner. It is possible that if this sentence had not been included in KRS 278.285, over the past 13 years we might have seen some utilities collecting funds from the residential and commercial customer classes and using a portion of those funds to expand the industrial DSM programs, where the "bang for the DSM buck" might have been greater than in the other customer classes. The resulting decrease in the utility's total demand might have deferred or eliminated the need for one or more expensive new power plants and thereby might have helped keep the rates lower for all customer classes.

Q. Did the Kentucky Public Service Commission implement the ratemaking standard cited above?

A. To answer that question accurately, one must review some history. The Kentucky PSC held an administrative case (Case No. 341) from 1992 to 1994, which led to proposed legislation, KRS 278.285. This statute, which was approved by the General Assembly and went into effect in July 1994, specified that demand-side management

(DSM) programs and cost recovery tariffs could be proposed by individual utility companies, and the Commission would evaluate, approve, disapprove, or modify each proposal on a case-by-case basis. The statute included the major loophole for certain industrial customers that I have discussed above.

I believe that the Commission in 1994 had all the legal authority it needed to reform rate structures even in the absence of KRS 278.285. The Commission could have issued a finding to the effect that reforming the traditional rate structure was necessary in order to remove the existing massive disincentives for utility companies to operate effective DSM programs that save significant amounts of energy. To fail to reform the rate structures would be to guarantee that each utility's least-cost strategy would diverge widely from its most financially advantageous strategy. A strong argument could be made that the statute was superfluous and, because of the loophole that was carved out for industrial customers, has done more harm than good over the past 13 years. Be that as it may, we are probably stuck with the statute for the foreseeable future and should direct our energies toward working together to find ways to enable it to function more effectively.

The DSM cost recovery mechanism now in place at E.ON and Duke Energy does not solve the problem identified by Moskovitz, even though it provides for the recovery of DSM program costs, lost revenue, and a shareholder incentive. Because the mechanism leaves revenue coupled to the volume of electricity sales, the rate structure simultaneously rewards DSM and the marketing of more electricity at all times. A complex web of incentives has been created at E.ON and Duke Energy, and the result is counterproductive. These utilities now have a financial incentive to operate DSM programs that look good on paper but save very little energy in practice. The traditional incentive for these two utilities to sell more electricity at all times has been unaffected by the DSM cost recovery mechanism that the Commission has put in place.

My conclusion is that to date, the Commission has failed to implement the intent of the federal statute cited above, which is that each utility's least-cost plan should be its most profitable course of action. As a result, Kentucky's utility companies have operated DSM programs for the past 13 years that have harvested miniscule energy savings at best. (Those DSM programs designed to shift peak loads to non-peak periods have tended to be somewhat larger and more effective.) Instead, our utilities have invested in new coal-fired power plants that have saddled customers with costs that are significantly higher than it would have cost to save the same amount of energy by improving end-use efficiency. Revenue requirements, electric rates, and customers' bills have ended up being higher than they might have been if each utility company's lowest-cost strategy had been implemented. Moreover, several additional coal-fired power plants are now under construction, and are certain to exert significant upward pressure on rates when they come on-line. These power plants may not have been needed if more DSM programs had been instituted during the past 13 years.

Q. How have Administrative Case 341 and the DSM statute affected the actions of EKPC over the past decade or so?

A. I am not aware that these developments have had any effect on EKPC's DSM and marketing programs. EKPC has never made use of the statute, never having submitted a proposal to the Commission for the recovery of program costs, lost revenue, and shared savings incentives for its token-scale DSM programs. When we look at EKPC's marketing programs and DSM programs together, the energy savings are zero. There is some shifting of demand from peak load periods to off-peak periods.

The Sierra Club and EKPC have been meeting periodically with other utilities and interested organizations in an informal organization known as the Utility Working Group. Recently the membership of the group was expanded to include additional organizations and it was renamed the Kentucky Energy Efficiency Working Group. In the course of our meetings, the utilities agreed to provide data about their DSM programs for the purpose of providing a factual basis for discussions about future DSM-related activities. EKPC provided a one-page summary to the Utility Working Group of its DSM and marketing program data for the year 2006. A printout of this data is included as Attachment A.

Q. What is the significance of this DSM and marketing program data?

A. The data provided by EKPC showed that its DSM activities are roughly comparable to those of the state's other utility companies. Like the other utilities, EKPC's overall level of effort devoted to programs that save energy is tiny – far less than one percent of revenue – even if we set aside EKPC's Electric Thermal Storage (ETS) program. When we consider ETS together with the other DSM programs, as EKPC itself does, the net effect on energy use in EKPC's service territory is zero.

Because DSM is generally a much cheaper energy resource than building new power plants, we may conclude with certainty that the plan that EKPC considers to be the most financially advantageous plan, which includes the construction of both coal-fired baseload power plants and combustion turbines (CTs) designed to burn natural gas and meet peak loads, cannot be the lowest-cost plan for its customers or for society as a whole.

Q. Have any Kentucky utility companies and the Commission ever attempted to address the problem of perverse incentives described by David Moskovitz in the report cited above?

A. Yes. Three utility companies – LG&E, KU, and ULH&P – had "pilot programs" for four or five years whereby decoupling was in effect in the residential customer class.

Q. What has been Kentucky's experience with these decoupling "pilot programs?"

A. Decoupling was in effect in LG&E's service territory during the period from 1994 through 1998 for the residential customer class. The decoupling method that the Commission had approved at that time was a formula that included four factors. The factor that related to decoupling was called the DRLS factor, which stood for DSM Revenue from Lost Sales. At the end of each 12-month period, the utility's non-variable revenue requirement (i.e., the total revenue less variable costs) that had been approved for the Residential Rate R in LG&E's most recent general rate case was adjusted to reflect changes in the number of customers and the usage per customer, as follows:

(1) the allowable revenue was made proportional to the number of customers, so if the number of residential customers increased by 1%, the allowable non-variable revenue from the residential class would be boosted by 1%.

(2) the allowable revenue was increased by a growth factor of 1.3% per year, to reflect the assumption that the average customer's energy use would increase at that rate.

The utility's revenue was thus recoupled to the number of customers and to an automatic growth factor. A similar decoupling formula was in effect for Union Light, Heat and Power (ULH&P) in northern Kentucky. If I recall correctly, some small commercial customers were also included in ULH&P's decoupling pilot program.

Because these formulas can be somewhat dry and hard to understand, it may be helpful to translate the implicit messages being sent by the Commission about financial incentives by means of its approved rate structure into words. The implicit message being sent to utility companies by the traditional ratemaking formula was as follows: "For the past 60 years, one unintended side-effect of our fixed-rate formula has been that if you boost energy sales to your customers, we will reward you handsomely; conversely, if you help your customers save large amounts of energy we will reduce your net income dramatically." The implicit message the Commission sent to LG&E and ULH&P in 1994 when it approved the decoupling formula described above was as follows: "For the next three years, on an experimental pilot basis in the residential customer class, if you help customers save energy we will stop punishing you financially; instead, we will give you a small reward. In regard to your larger customers, if you help them save large amounts of energy we will continue to cut your net income dramatically, in the same way we have done for the past 60 years." When the Commission approved the elimination of LG&E's decoupling pilot program in 1998, and a year or two later eliminated ULH&P's decoupling mechanism, it was saying, in effect, "Our limited, pilot-scale experiment in one customer class was all well and good, but we are now returning to the decades-old system whereby we will reward you for boosting sales to all customers and will cut your net income dramatically if you help your customers save energy."

I believe that the limited nature of Kentucky's experiment with decoupling had the effect of leaving largely unchanged the thinking patterns of many of the executives at

LG&E, KU, and ULH&P. Because decoupling applied only to one customer class rather than across the board, and because it was termed a "pilot project," most of the top executives may not have realized that decoupling was acting against the companies' entrenched, decades-old habit of trying to boost sales of electricity at all times. The pilot decoupling project for a subset of the utilities' customers may not have been sufficiently all-encompassing to affect these utilities' corporate cultures. Even if certain executives had been aware of the implications of decoupling, it is possible that this new understanding was not transmitted clearly to the staff in the field, for example, to the members of the marketing and customer service teams. For any given policy change to take hold within a utility company, which tends in general toward conservatism, it needs to be given a high profile by top management, transmitted to staff at all levels of the organization, and bolstered by changes in the personnel policies that determine the incentives employees will receive. To change a habit as firmly entrenched as the policy of boosting electricity sales would require a lot of leadership from top management, consistent effort, and time.

Q. Why did LG&E propose to the Commission that its residential decoupling pilot tariff be ended in 1998?

A. LG&E and KU, now merged and under the ownership of E.ON, became disillusioned with the residential decoupling pilot tariff as a result of a long-running dispute with the AG about the automatic growth factor. My recollection of the sequence of events is that after seeing the decoupling mechanism operate for a few years, the AG's representative on E.ON's DSM Collaborative concluded that the automatic growth factor was rewarding E.ON's shareholders with excessive net income unrelated to the company's DSM efforts. When E.ON declined to entertain the AG's motion to propose to the Commission that the growth factor be adjusted downward, the AG's representative elected to block progress on all issues in the Collaborative – which operated according to a consensus decision-making procedure – for approximately a year. E.ON later proposed ending both the decoupling pilot program and the DSM Collaborative, and replaced the latter with a DSM Advisory Committee that had no decision-making authority.

Q. Why did ULH&P propose to the Commission that its residential/ small commercial decoupling pilot tariff be ended a year or so later?

A. I believe that executives at Cinergy, which owned ULH&P, became concerned about fluctuations in the size of the decoupling balancing account. They also mentioned the possibility that the decoupling formula could be gamed by one or another party.

Q. Is there a rate structure that decouples revenues from sales that the Sierra Club can propose that could also eliminate the possibility of disputes over the automatic growth factor?

A. Yes; one such method of which I am aware is called statistical recoupling. In his report, *"Statistical Recoupling: A New Way To Break the Link Between Electric-Utility Sales and Revenues,"* Eric Hirst described three types of decoupling: recoupling revenues to determinants of fixed costs (e.g., California's Electric Revenue Adjustment Mechanism, or ERAM); recoupling revenues to the growth in the number of customers, also known as revenue-per-customer decoupling; and recoupling revenues to the determinants of electricity sales, also known as statistical recoupling. The type of decoupling that temporarily existed in Kentucky (for residential customers) was of the second type, revenue-per-customer decoupling.

Q. Is Eric Hirst a technical expert in the field that includes the subject of the report cited above?

A. Eric Hirst is a recognized expert in energy efficiency, DSM, and utility ratemaking concepts. He has been recognized by the Oak Ridge National Laboratory (ORNL) for "pioneering work on energy conservation, including development of energy demand models, data bases, and analyses of energy use trends, which has contributed to federal and state energy policies and programs and to demand-side planning by electric utilities." Eric Hirst has been at ORNL since 1970. His research focuses on the electric industry. Projects deal with unbundling generation and transmission services (ancillary services), bulk-power reliability, formation and operation of independent system operators, stranded (transition) costs, and the effects of changes in bulk-power markets on environmental quality. During the past 25 years, Hirst was on assignment for a year or more with Land and Water Fund of the Rockies (1992–93), Puget Sound Power & Light (1986–87), the Minnesota Energy Agency (1979), and the Federal Energy Administration (1974–75). Dr. Hirst holds a Ph.D. degree in mechanical engineering from Stanford University. Hirst has published almost 400 reports, journal articles, and book chapters. He was appointed a corporate fellow in 1985. (Source: http://www.ornl.gov/info/awards /cf/cfcitations/cfbios/hirst.shtm)

Chapters 4, 5 and 6 of his report on statistical recoupling (SR) are reproduced as Attachment B to this testimony.

Q. What problems associated with some types of decoupling would SR solve?

Two side-effects that can result from the first two types of decoupling – ERAM and revenue-per-customer decoupling – are that they may cause relatively large fluctuations in rates under certain conditions, and that they also change the allocation of certain risks between the utility and its customers, most notably the risks related to weather and economic recessions. If the weather is severe and energy usage increases, during the next period the decoupling formula will lower the electric rate and require the utility to return some of the revenue to customers. The formula would give rise to a similar refund if there is an economic boom and energy use per customer increases. Conversely, if the weather is mild and energy use falls, during the next period the decoupling formula will raise the rate per kWh and allow the utility to receive additional revenue from its customers. If there is an economic recession and energy use per customer decreases, during the next period the decoupling formula will raise the rate per kWh. In some cases, such as Maine's and Washington's experience with decoupling in the early 1990s, the rate effects of weather and regional economic conditions dwarfed the rate effects of energy efficiency programs.

SR addresses these issues and reduces the size of the fluctuations in the balancing account and consequently in electric rates. It does so by recoupling the revenues to the main factors that affect the amount of energy consumed. To develop the SR formula, a regression model is developed using the past 10 to 15 years of data, for energy consumption as a function of variables such as heating degree-days, cooling degree-days, the number of customers, the retail price of electricity, and a measure of economic activity in the region such as industrial output. Hirst's SR model also includes a first-order autoregressive term designed to reduce the standard error in the model's other coefficients. The allowable revenues for subsequent years are determined by using the same regression formula in conjunction with each year's variable data. *Ibid.,* pp. 33-36.

The result is that revenues are decoupled from sales – i.e., the Commission would stop punishing the utility financially for helping customers save energy – and the year-to-year rate fluctuations that can result from changes in weather and economic conditions are moderated. Statistical recoupling appears to be the decoupling approach that would be most beneficial for Kentucky.

Q. If SR were to be implemented for EKPC as a result of this rate case, is there a significant risk that EKPC could "over-recover" large amounts of money from customers?

A. I believe that the risk of massive "over-recovery" is negligible, for three reasons:

a) The allowable revenue, as calculated by the regression model described above, would be likely to be very close to the dollar amount set by the Commission using the traditional fixed-rate approach. This would continue to be the case until the cumulative impacts of EKPC's new DSM programs had time to grow comparatively large.

b) EKPC is a not-for-profit cooperative corporation and can return excess net income to its customers. It has done so in the past.

c) As a result of EKPC's aggressive powerplant-building strategy, rate cases are likely to be coming up frequently during the coming decade. Each rate case accomplishes two things: 1) it resets the effects of DSM programs by bringing their ongoing costs into EKPC's rate base; and 2) it offers an opportunity to adjust the decoupling/SR formula in the unlikely event that it is shown to be failing to achieve its regulatory purposes.

My conclusion is that in the current proceeding that involves a cooperative corporation, the risk arising from the implementation of SR of large-scale over- or under-recovery is negligible. This case is an ideal time to implement a decoupling mechanism such as SR.

Q. If frequent rate cases are likely at EKPC, why is decoupling needed at all?

A. We are virtually always "between rate cases," even when they occur frequently. To be precise, the only time we are not between rate cases is on the day the Commission issues its final Order in the rate case and thereby establishes the revenue requirements and rate structures that will be in effect during the coming time period (until the next rate case).

Q. Is SR sufficient to align all parties' incentives in a way consistent with the utility's lowest-cost plan?

A. No, SR only removes the huge financial disincentive for energy efficiency that now exists. Another necessary element of the rate structure is a positive incentive to induce EKPC and its member co-ops to embark on a dramatically different strategy than the familiar pattern we have seen for many decades. Kentucky's DSM statute specifically envisions the option of including a tariff provision that rewards the utility for "implementing cost-effective demand-side management programs." [KRS 278.285, Section (2)]

I recommend that this incentive take the form of a shared savings element, in order to provide an incentive for the utility to operate cost-effective DSM programs. The shared savings element would preferably be based on actual measured savings, where these can be obtained, rather than extrapolations from engineering estimates. Several utilities in other states are allowed to recover a percentage, often approximately 15%, of the value of the energy savings, as a financial incentive. The actual savings can be measured or estimated using well-known measurement and verification (M&V) protocols. The Division of Energy Efficiency and Renewable Energy within the Governor's Office of Energy Policy has experience working with widely-accepted M&V protocols.

Another element in the tariff would allow EKPC to recover its DSM program costs, as envisioned by the DSM statute.

Q. Is it feasible for these proposals that relate to decoupling and incentives to be implemented in this rate case?

A. Yes, it would be eminently feasible, reasonable, and straightforward to implement our proposals in this rate case. Following the example of the decoupling pilot programs that were tried by LG&E, KU, and ULH&P, the Commission could approve a new tariff for EKPC that would add a single line to customers' bills. In order to communicate the purpose and function of this element to customers in the clearest possible way, I propose that this item on customers' bills be called either the "Efficiency Savings Factor" or the "Efficiency Shared Savings Factor."

Q. What elements would the "Efficiency Savings Factor" include?

A. It would include the following three elements:

1) The SR factor (standing for statistical recoupling), which would embody the regression model that would be applied to each year's data to yield EKPC's allowable revenue. The SR factor would compare the allowable revenue to the actual revenue collected by EKPC, and would be applied via the mechanism of a balancing account.

2) An element to allow EKPC to recover its legitimate DSM program costs.

3) A shared savings incentive element, as discussed above.

Q. Is it the Sierra Club's position that SR is the only reasonable solution to the problem of counterproductive incentives associated with EKPC's traditional rate structure?

A. No, the Sierra Club is not irrevocably wedded to SR. There are other ways to structure EKPC's tariffs so as to decouple revenues from sales, but the drawbacks of these other decoupling approaches appear to be greater than the drawbacks of SR. We urge that very serious consideration be given to the potential advantages that SR appears to offer. By far the most important of these advantages is that SR decouples the utility's revenue from its level of electricity sales without causing large, unpredictable fluctuations in rates.

Q. In addition to the decoupling/SR/shared-savings proposal described above, does the Sierra Club have other proposals that relate to EKPC's rate structure?

A. Yes. EKPC's DSM programs have historically been small, have saved very little energy, and have improperly been lumped together with marketing programs that are designed to "fill valleys" by boosting energy consumption during periods of low demand. The Sierra Club believes that EKPC needs to reevaluate its set of DSM and marketing programs, keeping in mind the goal of expanding those cost-effective programs that would save significant amounts of energy. New DSM program ideas should be considered and evaluated using the standard California benefit/cost tests. EKPC should phase out the Electric Thermal Storage programs that boost energy consumption, and significantly increase its annual level of investment in cost-effective programs that improve energy efficiency in customers' homes and businesses. The Sierra Club stands ready and willing to work cooperatively with EKPC to develop and assess new DSM program ideas.

Q. What modifications to EKPC's tariff sheets would be appropriate if the Commission were to implement the Sierra Club's proposals related to SR and DSM?

A. The Sierra Club recommends the following modifications:

1) A new section would be added to the Wholesale Power Rate Schedule titled either the "Efficiency Savings Adjustment" or the "Efficiency Shared Savings Adjustment." This tariff would specify the method to be used to calculate the Efficiency Savings Factor, and would include the three elements described on page 24 above.

2) The following tariff sheets should be deleted: Section DSM-1, Touchstone Energy Manufactured Home Program; Section DSM-2, Touchstone Energy Home Program; and Section DSM-3, Direct Load Control of Water Heaters and Air-Conditioners Program. This is not to say that these programs themselves should be cancelled, but simply that separate tariff sheets relating to specific DSM programs would not be necessary once a general SR and shared savings tariff had been implemented. To have a published tariff sheet for each DSM program makes it unnecessarily difficult for EKPC to make adjustments in the terms of these programs from time to time as the need may arise. Other utility companies in Kentucky have a tariff that specifies the DSM cost recovery formula without listing the details of any particular DSM program.

Q. Does the Sierra Club have other proposals that relate to EKPC's rate structure?

A. Yes; the tariffs that relate to qualified cogeneration and small power production facilities need to be revised.

Q. Is an examination of these tariffs properly within the scope of this proceeding?

A. Yes. In its Order of June 18, 2007, the Commission stated that "all tariff provisions, including the QF tariff, are subject to review in this proceeding." (Order, pp.2-3)

Q. What is wrong with EKPC's current tariffs for qualified cogeneration and small power production facilities?

A. In brief, there is no reason to believe that the current tariffs accurately reflect EKPC's long-run avoided costs. The Kentucky regulation 807 KAR 5:054 was enacted in order to implement the rules that the Federal Energy Regulatory Commission (FERC) adopted pursuant to Title II of the Public Utility Regulatory Policies Act of 1978 (PURPA), Section 210(f). The intent of this title was, in part, "to encourage cogeneration and small power production by requiring electric utilities to sell electricity to qualifying cogeneration and small power production facilities and purchase electricity from such facilities." (807 KAR 5:054, Necessity, Function and Conformity)

Section 1 of 807 KAR 5:054 provides the following definition: "(1) 'Avoided costs' means incremental costs to an electric utility of electric energy or capacity or both which, if not for the purchase from the qualifying facility, the utility would generate itself or purchase from another source."

Section 7 of 807 KAR 5:054 establishes standards for the rates that a utility company shall pay for power and/or energy produced by qualified facilities that have either a design capacity of 100 kW or less or a design capacity of over 100 kW. In both cases, the standard is the same: such "rates shall be just and reasonable to the electric customer of the utility, in the public interest and nondiscriminatory."

The date of issue of EKPC's current tariffs for qualified cogeneration and small power production facilities was December 2, 2004, and the tariffs became effective on January 1, 2005. If these tariffs reflected EKPC's long-run avoided costs at the beginning of 2005, then for the tariffs to continue to reflect the avoided costs today, one would need to assume that EKPC's projected energy and capacity costs have not changed during the 30 intervening months. Some of the factors that may have affected avoided costs in the past two and a half years include but are not limited to the following:

- increases in the market prices of both coal and natural gas;
- changes in the market prices of coal-fired and natural gas-fired generating units;
- a decline in EKPC's credit rating and consequently its ability to borrow money at below-market rates;
- a decrease in the availability and price of power in the regional wholesale power market;
- trends in the regulatory climate, nationally and internationally, that suggest that large-scale emitters of greenhouse gases will need to begin compensating society for the global warming impacts of their emissions; and
- advances in the scientific community's understanding of climate change and the effects of greenhouse gases on the Earth's climate.

It would be unreasonable to assume that these and other factors have not caused EKPC's avoided costs to change between January 2005 and today. Most or all of these factors would tend to increase EKPC's avoided cost; i.e., they would increase the value to EKPC of electricity generated by cogenerators and small power producers, compared to electricity that EKPC would generate itself. If EKPC's avoided costs have in fact increased as a result of these and other factors, the QF tariffs should be revised upwards as well.

Q. Are there any other problems with EKPC's current tariffs for qualified cogeneration and small power production facilities?

A. Yes, EKPC's existing QF tariffs contain some serious anomalies.

Given the market conditions for purchased power in Kentucky, it is not at all apparent why EKPC's QF rates are so much lower in the summer than in the winter.

The tariffs fluctuate from year to year for no apparent reason. The summer off-peak payment for energy generated by facilities over 100 kW, for example, is set at \$0.01991 per kWh in 2005, \$0.02115 in 2006, \$0.02129 in 2007, \$0.01874 in 2008, and \$0.01667 in 2009. The rates for facilities with capacities below 100 kW show a similar pattern of increase and subsequent decline. If these rates had been based on long-term avoided costs, one would normally expect that they would steadily increase over time to reflect the general rate of inflation. A potential cogenerator or small power producer might look at the trend represented by the years 2007, 2008 and 2009 and conclude that EKPC intends to continue reducing the amount it will pay during the out-years of 2010 and beyond. That factor in itself could act to deter potential developers of cogeneration and small power production projects in EKPC's service territory.

EKPC's existing tariffs include both an energy and a capacity component. To get an approximate idea of the relative size of these components, I hypothesized a QF facility with a net capacity of 200 kW that delivers its full production to the grid at a steady rate all year long. The total amount of energy delivered would be 1,753 MWh. Using EKPC's buyback rates listed in the tariff for the year 2007, the total amount paid for energy would be $61,462, which would correspond to an average payment of 3.50 cents per kWh. If EKPC were to dispatch the power produced by the QF facility, the amount paid for capacity would be $1,694 per year, i.e., only 2.7% of the total payment, while if EKPC did not dispatch the QF facility, the amount paid for capacity would be $1,929 per year, i.e., only 3.0% of the total payment. In either case, the capacity component is negligible compared to the energy component. There is no obvious reason why capacity should be so much less valuable to EKPC than energy. Moreover, there is no reason whatsoever why EKPC should pay more for capacity that the utility does not dispatch than capacity it does dispatch.

I consider these anomalies to be indicators that these tariffs are long overdue for comprehensive reevaluation and revision. Another implication, even more important, is that whatever methodology has been used in the past to determine EKPC's avoided costs must either be severely flawed, or must have been incorrectly applied. The same methodology cannot be relied on to produce fair, just and reasonable QF tariffs at this time or in the future. It must be discarded in favor of a new approach.

In addition to anomalous pricing provisions, the tariffs contain certain terms and conditions that may be unreasonably discriminatory against QF facilities. These include the following:

"1. All power from a Qualifying Facility (QF) will be sold only to East Kentucky Power Cooperative."

Perhaps there is some technical reason for this provision, but what it might be is not readily apparent to me. This provision appears to interfere unduly with the business decisions of the QF. I would suggest that it be deleted from the tariff.

"5. Qualifying Facility shall reimburse EKPC and its member cooperative for all costs incurred as a result of interconnecting with the QF, including operation, maintenance, administration, and billing."

When EKPC builds a new power plant, the utility incurs all costs relating to interconnecting the plant with EKPC's system. Those costs are considered part of the cost of obtaining the generation resource. It seems to me that if a QF meets EKPC's other valid requirements and appears to be likely provide reasonably-priced power that EKPC will need during the next several years, it would be fair, just and reasonable for EKPC to cover some or all of the costs of interconnection.

"6. Qualifying Facility shall obtain insurance in the following minimum amounts for each occurrence:

a. Public Liability for Bodily Injury - $1,000,000.00

b. Property Damage - $500,000.00"

Although it might be prudent for a QF to obtain insurance in these amounts or some other amounts, this provision appears to interfere unduly with the business decisions of the QF. I would suggest that it be deleted from the tariff.

"7. Initial contract term shall be for a minimum of twenty years."

This provision is clearly unreasonable and discriminatory against QFs. Presumably the contract between EKPC and the QF would contain a clause specifying that the QF would pay a penalty for failure to continue to provide power for the full 20-year contract period. No entrepreneurial company can guarantee that it will be in business at its present location for the next two decades. No individual could reasonably be expected to put off his or her relocation plans for a decade or more. This provision should be amended to a maximum of five years.

"8. Qualifying Facilities proposing to supply as available (non-firm) electric power shall not be entitled to a capacity payment."

Although the capacity payments listed in EKPC's current QF tariffs are so low as to make this provision largely irrelevant, we cannot assume that the capacity payments will not be increased significantly as a result of this case. This provision would then become more important. The logic behind it appears to rest on the assumption that a QF that supplies non-firm electric power will not be supplying any power during times when EKPC needs it the most. The implication would be that the QF will be of no use in helping EKPC meet its peak loads. In reality, there is a certain finite probability that the QF will be supplying power when it is most needed. This probability could be estimated in advance, or it could be inferred after tracking the QF's performance for a certain amount of time, or both. In any case, the provision should be amended to allow for a capacity payment if there is a reasonable likelihood that the QF will be supplying power to EKPC during the utility's peak load periods.

In sum, the provisions listed above are fairly representative examples of the types of interconnection barriers that are frequently encountered throughout the United States. An illuminating analysis of such barriers is provided in the report, "Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects." (R. Brent Alderfer, M. Monika Eldridge, and Thomas J. Starrs, National Renewable Energy Laboratory, May 2000; publication number NREL/SR-200-28053. It is available online at http://www.nrel.gov/docs /fy00osti/ 28053.pdf.) Of 65 case studies for which sufficient information existed to include in the report, 58 projects encountered utility-related barriers. Sometimes the barriers were so severe as to prevent the project from being implemented.

EKPC and the Commission should reconsider the terms and conditions listed in EKPC's QF tariffs, and ask how cogeneration and small power production might be facilitated and encouraged rather than discouraged and blocked. The purpose of the Sierra Club's proposals above that relate to the QF tariff is not to "punish" EKPC or to jeopardize any of its legitimate economic interests, but to fulfill the intent of PURPA and Section 7 of 807 KAR 5:054, and to ensure that the cited standard is implemented: that such "rates shall be just and reasonable to the electric customer of the utility, in the public interest and nondiscriminatory."

Q. If EKPC's existing tariffs for qualified cogeneration and small power production facilities are incorrect, what should these tariffs be instead?

A. I would like to answer that question in two phases: first, by providing a guideline that would function as a lower bound, and then by proposing a somewhat higher level at which I believe the tariffs should be set.

If EKPC's QF tariffs do not approach the member co-ops' wholesale rate, they will virtually never be used. Until recently, EKPC's member distribution cooperatives had full-requirements contracts that limited their ability to purchase power from sources other than EKPC. Since these contracts were amended in October 2003, that is no longer the case. Any given member co-op may obtain up to 15% of its power from other sources, until the total amount purchased by all of EKPC's member co-ops reaches 5% of

EKPC's coincident peak demand. (EKPC's Response to Sierra Club's 1st Data Request No. 10)

Given the set of incentives faced by member cooperatives as a result of EKPC's wholesale tariffs, it would be reasonable to assume that a typical distribution co-op would be willing to pay a cogenerator or small power producer a rate approximately equal to the wholesale rate that the co-op pays to EKPC. The amount a distribution co-op would be willing to pay might be slightly less than EKPC's wholesale rate if the co-op wishes to be compensated for its administrative costs, or somewhat more than the wholesale rate if the co-op believes the electricity from the QF facility is more valuable to the co-op than the electricity it obtains from EKPC's centralized power plants. The wholesale rate paid by the distribution co-op, however, would constitute a reasonable starting point, guidepost, or lower bound. If EKPC's tariffs for cogenerators and small power producers were significantly lower than its wholesale rates to its member co-ops, any rational QF facility would contract with the appropriate member co-op instead. Virtually no one would contract with EKPC directly, and its QF tariffs would remain unused. EKPC's tariff would, in effect, become unreasonable and discriminatory against QF facilities because it would discourage all purchases from QF facilities above and beyond the amount that had already been facilitated by the distribution co-ops on their own. The intent of PURPA Section 210(f) to encourage cogeneration and small power production would be thwarted, and the economic interests of customers, as well as the public interest generally, would be harmed.

The Sierra Club has a major concern, however, about the possibility that QFs that use highly-polluting technologies and fuels to generate power – for example, small diesel-fueled generators that lack pollution control equipment – may take advantage of the policy implied above, and create what has been called "a thousand points of soot." Whatever rates, terms and conditions may go into effect for QFs, it is essential that they not provide any significant economic incentives to dramatically increase the amount of electricity that is generated in Kentucky using highly-polluting fuels and technologies. A method to address this concern will be outlined below.

Q. Your discussion above relates to a lower bound for the cogeneration and small power production tariffs. What is the Sierra Club's proposal for what the QF tariffs should be?

A. The Sierra Club proposes that the QF tariffs establish rates, terms and conditions that are favorable for environmentally sound generation technologies and unfavorable for highly-polluting technologies. We have been able to come up with two different ways to accomplish this goal:

1) to set QF tariffs that are very low – approximately 1.0 cent per kWh – for power from generating technologies that cause more environmental damage per delivered kWh than EKPC's existing fleet of generating units; tariffs that are reasonably high – approximately the wholesale rate – for power from natural gas-fired generating units, and tariffs that are quite generous – approximately 9 to 10 cents per kWh – for power provided by clean, renewable energy sources; Or:

2) to set QF tariffs that are very low for generating technologies that cause more environmental damage per delivered kWh than EKPC's existing fleet of generating units, and to allow environmentally sound generation technologies to use net metering terms.

Q. What is net metering?

A. KRS 278.465 contains the following definition:

"(4) 'Net metering' means measuring the difference between the electricity supplied by the electric grid and the electricity generated by an eligible customer-generator that is fed back to the electric grid over a billing period." In effect, the utility company pays the cogenerator or small power producer the retail rate for the electricity it delivers to the grid.

Q. How would you define an "environmentally sound generation technology?"

A. A generating technology that causes less environmental damage per delivered kWh than EKPC's existing fleet of generating units.

What must be avoided at all costs is for the Commission to solve one problem – i.e., to eliminate the existing discriminatory barriers against qualifying facilities – while simultaneously ushering in the creation of a thousand points of soot.

Q. In making these proposals, aren't you completely losing sight of the concept of "avoided costs," on which the QF tariffs are supposed to be based?

A. Not at all. According to the Energy Dictionary, published online by EnergyVortex.com, the definition of avoided cost is as follows:

> Avoided cost is the marginal cost for the same amount of energy acquired through another means such as construction of a new production facility or purchase from an alternate supplier. For example, a megawatt-hour's avoided cost is the relative amount it would cost a customer to acquire this energy through the development of a new generating facility or acquisition of a new supplier. Short-run avoided cost refers to avoided cost calculated based on energy acquisition costs plus ongoing expenses. Long-run avoided cost factors in necessary long-term costs including capital expenditures for facilities and infrastructure upgrades. Avoided cost is typically used to calculate a fair price for energy produced by cogenerators and other energy producers that meet the specifications of the Public Utility Regulatory Policies Act of 1978. The use of avoided cost rates for cogenerated energy is intended to prevent waste and improve both efficiency and cleanliness by insuring

> that fair market prices paid for energy generated from renewable resources, small producers and others.

It is important to note that the definition of avoided cost includes a reference to the relative "cleanliness" of renewable energy sources. One could paraphrase the definition of avoided cost by saying that the avoided cost is what the power is worth to the utility company in the long term, taking into account factors such as efficiency and environmental cleanliness.

In 2006, the Commission conducted an administrative case, No. 2006-00045, styled, "Consideration of the Requirements of the Federal Energy Policy Act of 2005 Regarding Time-Based Metering, Demand Response and Interconnection Service." In the context of discussing potential policies the Commission might enact in regard to the interconnection of QFs to the electric systems operated by Kentucky's jurisdictional utilities, several of the utilities expressed positions that indicated that they believe that the energy produced by QFs is worth very little to the utility, to the system, and to other customers. Michael Leake of E.ON, for example, in his testimony of 5/18/06, stated that "The impact of implementing the EPAct 2005 interconnection standard should not be significant, provided interconnected generation is not required to be incorporated into system resource plans due to its questionable availability, is not subsidized beyond avoided cost through rate incentives, and all associated costs of interconnection are assigned to the customers requesting interconnection." (Testimony, p.1, lines 15-20) We know from other testimony presented in that case that Mr. Leake holds that the value of "avoided cost" to E.ON is extremely low, significantly lower than the avoided cost value EKPC has been using. Officials from other utility companies raised similar alarms about the costs that QFs would impose on the system, and were similarly dismissive of its potential economic and environmental benefits. None of the utility company representatives mentioned the possibility that the benefits that QFs could contribute to the electric system might significantly outweigh any costs they might cause.

There is a large amount of evidence, however, that electricity produced by QFs can actually be worth a great deal to the utility company and to society as a whole, particularly during periods when the demand for electricity is increasing. In 2002 the Rocky Mountain Institute published a revolutionary book called *Small Is Profitable*, which describes a large number of economic benefits that accrue to the electrical system when small-scale, distributed generation is added to the grid. When these benefits are taken together, they almost always far outweigh the additional utility costs that have been emphasized by the utility personnel who presented testimony in Administrative Case No. 2006-00045. Although the executive summary of *Small Is Profitable* is available on the internet via the web site http://www.smallisprofitable.org/index.html, we have reprinted it here in its entirety as Attachment C because it is directly relevant to the question of what such power is worth to the utility, i.e., it is relevant to the issue of avoided cost.

Q. Does Amory Lovins, the lead author of the book, *Small Is Profitable,* have any experience that would qualify him as an established expert in the field of distributed energy technology?

A. Amory B. Lovins, chief executive officer of Rocky Mountain Institute, is a consultant experimental physicist educated at Harvard and Oxford. He has received an Oxford MA (by virtue of being a don), nine honorary doctorates, a MacArthur Fellowship, the Heinz, Lindbergh, Right Livelihood ("Alternative Nobel"), World Technology, and TIME Hero for the Planet awards, the Happold Medal, and the Nissan, Shingo, Mitchell, and Onassis Prizes. His work focuses on transforming the hydrocarbon automobile, real estate, electricity, water, semiconductor, and several other sectors toward advanced resource productivity. He has briefed eighteen heads of state, held several visiting academic chairs, authored or co-authored twenty-nine books and hundreds of papers, and consulted for scores of industries and governments worldwide. The Wall Street Journal named Mr. Lovins one of thirty-nine people worldwide "most likely to change the course of business in the '90s"; Newsweek has praised him as "one of the Western world's most influential energy thinkers"; and Car magazine ranked him the twenty-second most powerful person in the global automotive industry.

Q. What are the implications of the findings of the book, *Small Is Profitable,* as expressed in its executive summary?

A. There are several important implications. If Lovins and his team are correct that the lower financial risks associated with small-scale distributed resources raise their value by almost "an order of magnitude (factor of ten) for renewables, and by about 3–5-fold for nonrenewables;" and that "electrical-engineering benefits – lower grid costs and losses, better fault management, reactive support, etc. – usually provide another ~2-3-fold value gain, but more if the distribution grid is congested or if premium power quality or reliability are required," then the power produced by QF facilities is very valuable indeed to EKPC and its customers. If the analyses in the book are even close to correct, then the avoided cost of small-scale QF-delivered power – i.e., its economic value to EKPC – is much higher than the retail price. As the Sierra Club concluded in its public comments in Administrative Case No. 2006-00045, "The buyback rate of 15 cents per kWh for photovoltaic-generated electricity that is now in effect in the Tennessee Valley

Authority's service territory is not at all unreasonable" for utility companies in Kentucky to pay to small-scale QF facilities that use clean, renewable energy technologies.

In order to begin to substantiate the dramatic economic claims made in this book, we have included the book's list of 207 benefits of small-scale, distributed resources as Attachment D.

Q. Is there any logical connection between the Sierra Club's various proposals related to rate structure that you have outlined above?

A. Yes. SR, a specific type of decoupling, is the most important reform we are proposing. The reason is that if decoupling/SR is not implemented, EKPC will continue to be punished financially if it helps its ultimate customers save energy or if it enters into contracts with cogenerators or small power producers. EKPC will continue to have a powerful financial incentive not to operate effective energy-saving DSM programs. If the Commission were to implement the Sierra Club's proposals that relate to EKPC's DSM programs and QF tariffs, in the absence of decoupling/SR, EKPC would have a very strong incentive to find clever ways to make sure that the DSM programs fail to save much energy and that QFs do not enter into contracts with EKPC or its member cooperatives.

On the other hand, if the Commission were to implement decoupling/SR and not necessarily implement all of the Sierra Club's other proposals related to DSM and QF tariffs, EKPC itself would soon come to understand that these other programs could benefit the utility as well as its customers. The incentive structure would have changed enough to induce EKPC to change its perspective, strategy, and behavior.

If the Commission were to implement all of our proposals, decoupling/SR would have the effect of enhancing EKPC's motivation to implement cost-effective DSM and encourage the proliferation of non-polluting QFs in the most effective way possible. Within a few years after the adoption of these reforms, we would expect to see a leveling off of projected load growth, an easing of the upward pressure on EKPC's rates (with consequent economic benefits accruing to all customers), a dramatic reduction in the amount of energy being wasted in all of EKPC's customer classes, and a financially sound cooperative utility company whose financial incentives would be better aligned with those of its ultimate customers.

Q. Does that conclude your testimony?

A. Yes.

I, Geoffrey M. Young, hereby certify that I prepared or caused to be prepared the foregoing testimony to be filed in the above-styled proceeding.

Geoffrey M. Young — 6/29/07
Geoffrey M. Young — Date

Notarized by B Todd Reynolds 6/29/07
My commission expires

OFFICIAL SEAL
B. TODD REYNOLDS
NOTARY PUBLIC - KENTUCKY
FAYETTE COUNTY
My Comm. Expires Mar. 15, 2011

CERTIFICATE OF SERVICE

I hereby certify that an original and thirteen copies of the foregoing prepared testimony were delivered 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 ~~27th~~ 29th G.M.Y. day of June, 2007:

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Attachment A

EKPC's Existing DSM and Marketing Programs

Data Provided to the Utility Working Group

	DSM program name	customer class	brief description of what the program does	# of new partici-pants in 2006	cumulative # of participants	est. # of potential participants	MWh saved in 2006*	demand reduc-tion in 2006, MW**	program costs in 2006, $	lost revenue in 2006, $	shareholder incentive in 2006, $	Total Resource Cost ratio	Societal Benefit/Cost ratio	Participant Benefit/Cost ratio
1	electric thermal storage propane	residential	discounted rate for off-peak charging of ETS system	250	6973	0	-44,906	-0.4	see note below	N/A	N/A	1.18	1.04	1.19
2	electric thermal storage furnace	residential	discounted rate for off-peak charging of ETS system	in above total	in above total	in above total	in above total	25.8	see note below	N/A	N/A	2.33	2.48	1.60
3	electric water heater new construction	residential	choose a high efficiency electric water heater; purchaser gets a heater discount	690	9785	0	-854	0.8	see note below	N/A	N/A	1.84	2.19	3.07
4	electric water heater retrofit	residential	choose a high efficiency electric water heater; purchaser gets a heater discount	in above total	in above total	in above total	in above total	-1.0	see note below	N/A	N/A	0.54	0.49	0.76
5	geothermal heating & cooling	residential	choose geothermal heating and cooling systems	150	4902	0	14,224	23.4	see note below	N/A	N/A	4.64	5.23	1.85
6	air source heat pump new construction	residential	incentives for customer to install a high efficiency air source heat pump	660	4754	0	-3,783	-5.1	see note below	N/A	N/A	0.46	0.47	0.90
7	air source heat pump retrofit	residential	incentives for customer to install a high efficiency air source heat pump	in above total	in above total	in above total	in above total	-6.2	see note below	N/A	N/A	0.47	0.47	0.95
8	tune up HVAC maintenance	residential	clean and fine tune HVAC eqpt and thermostat, seal ductwork	350	4387	0	6,467	5.0	see note below	N/A	N/A	4.20	4.76	3.22
9	button-up weatherization	residential	requires the installation of insulation materials or the use of other weatherization techniques to reduce heat loss in the home	500	8085	0	21,181	16.4	see note below	N/A	N/A	6.80	7.79	2.95
10	compact fluorescent lighting	residential	give consumer 2 compact fluorescent bulbs each year to replace 2 60-watt incandescent light bulbs	<37700	37700	377000	3,698	0.6	see note below	N/A	N/A	21.47	25.04	infinite
11	touchstone energy geothermal heat pump home	residential	geothermal system and higher standards of thermal integrity to use 30% less energy	<40	40	400	244	0.3	see note below	N/A	N/A	4.68	5.35	1.36
12	touchstone energy air source heat pump home	residential	high efficiency air source heat pump and higher standards of thermal integrity to use 30% less energy	<100	100	1000	238	0.2	see note below	N/A	N/A	1.65	1.92	0.84
13	touchstone energy manufactured home	residential	all electric manufactured home built to Energy Star® specs, typically uses 30% less energy; rebate from local cooperative.	<10	10	100	56	0.0	see note below	N/A	N/A	5.75	6.74	3.34
14	dual fuel air source heat pump with propane retrofit	residential	use high effiency air source heat pump until outside air temperature gets too low, then switch to the fossil fuel backup--saves on EKP's system peak	<100	100	1000	-436	0.0	see note below	N/A	N/A	2.31	2.27	1.70
15	commercial lighting	commercial	incentives offered to C&I customers to install high efficiency lamps and ballasts.	<570	570	5700	2,788	0.3	see note below	N/A	N/A	2.55	3.00	2.25
16	commercial efficient HVAC	commercial	incentives to install unitary commercial air conditioners and heat pumps that exceed the 2006 Federal Guidelines of 13 SEER and 7.7 HSPF	<150	150	1500	228	0.0	see note below	N/A	N/A	2.37	2.81	1.81
17	industrial premium motors	industrial	encourage C&I customers to upgrade in service motor stock to premium efficiency motors	<50	50	500	676	0.1	see note below	N/A	N/A	4.75	5.76	3.83
							*a negative number signifies an increase in energy usage	**a negative number signifies an increase in peak demand	NOTE: The total cost for the 17 DSM programs for 2006 is $1,884,530, which includes EKP and distribution costs.					

Attachment B

Chapters 4, 5 and 6 of "Statistical Recoupling: A New Way to Break the Link Between Electricity Sales and Revenues," by Eric Hirst, 1993, Oak Ridge National Laboratory; Contract No. DE-AC05-84-OR21400.

ORNL/CON-372

ENERGY DIVISION

STATISTICAL RECOUPLING:
A NEW WAY TO BREAK THE LINK
BETWEEN ELECTRIC-UTILITY SALES AND REVENUES

ERIC HIRST

September 1993

Sponsored by
Office of Energy Efficiency and Renewable Energy
U.S. Department of Energy

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MARTIN MARIETTA ENERGY SYSTEMS, INC.
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for
U.S. DEPARTMENT OF ENERGY

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STATISTICAL RECOUPLING CONCEPTS

I developed a new method called statistical recoupling. This decoupling approach should interest utilities and commissions that do not want to adopt an attrition mechanism (in which allowed revenues are tied to the determinants of fixed costs) and that are concerned about the decoupling-induced changes in electricity prices that have occurred in recent years. This new mechanism minimizes changes from current rate making while severing the link between sales and revenues. One way to accomplish these goals is to let the utility retain the risks associated with fluctuations in the weather, the local economy, and customer growth, as it does under current regulation.

Like other decoupling mechanisms, SR involves two steps. The first step decouples revenues from electricity sales. In the second step, revenues are recoupled to statistical estimates of electricity use.

Implementing an SR mechanism requires the use of statistical models that explain well the effects of weather and economic activity on electricity sales. Such a system might be developed as follows. The utility would statistically analyze historical data (e.g., for the past 10 to 15 years) on quarterly or monthly electricity sales as a function of weather severity (e.g., heating and cooling degree days), service-area economic activity (e.g., income or employment), retail electricity prices, and other factors that materially affected electricity sales. This model would be estimated either separately for each customer class or for all retail sales in aggregate. For example, the model might have the following form:

$$E_{it} = a_i + b_i * DD_t + c_i * Y_t + d_i * P_t + e_i * C_t + \ldots ,$$

where

E is electricity use (GWh) for month or quarter t and customer class i;

DD is a measure of weather severity (such as heating or cooling degree days);

Y is a measure of economic activity;

P is retail electricity price;

C is the number of utility customers;

... represents other factors that affect electricity use; and a, b, c, d, and e are coefficients that are statistically determined from historical data.

The coefficients from this statistical model would then be used to estimate electricity use for each future year, given the actual weather patterns, economic conditions, and electricity prices for that year. For example, the utility might use data from 1975 to 1991 to create this model. The model would then be used to calculate electricity use for the year 1993, based on actual weather, economic conditions, and electricity prices for 1993. The utility's allowed revenue in 1993 would then be the product of the computed electricity use (E') and the "fixed" price of electricity (P_f) summed over all the retail customer classes i:

$$\text{Allowed revenues}_{1993} = \sum_i (E'_{i,1993} * P_{f\,i,1993}) \,.$$

The difference between actual 1993 electric revenues and the allowed revenues is the amount of money flowing through the utility's recoupling account:

$$\text{Recoupling account}_{1993} = \sum_i [P_{f\,i,1993} * (E'_{i,1993} - E_{i,1993})] \,.$$

P_f is the fixed-cost component of retail electricity prices. It is lower than the average retail electricity price for two reasons. First, it is adjusted down to remove the amount of revenue collected through the monthly customer charge. Second, it is adjusted down to reflect the base energy cost (P_v, either the variable cost allowed in the utility's current FAC or, for utilities without a FAC, the actual variable cost for that year).* That is:

$$P_f = \frac{\text{Retail revenue} - \text{Revenue from customer charges}}{\text{Retail sales}} - P_v$$

Typically, P_f is 50 to 75% of the average retail electricity price.

If the recoupling account is positive (i.e., the utility was authorized to collect more money than it did), it will raise the price of electricity the next year to recover this difference. Of course, if the recoupling account is negative, the price will be reduced during the following year.

While the models used in SR are virtually identical to those used by utilities, the application is quite different. Utilities routinely estimate the effects of weather, the economy, and other factors on electricity sales as part of their short- and long-term forecasting efforts.

When utilities use their models to forecast electricity sales, they must make assumptions about the values for the explanatory variables. For example, a utility in 1993

*P_v must be calculated at the customer meter (and not at the power plant busbar) to appropriately account for line losses. Its calculation depends on the particular FAC, if any, used by the utility.

wanting to forecast sales for 1994 and 1995 will have to assume values for income, number of customers, and other factors for these two future years. However, in SR, these models are used to determine allowed sales for the most recent year. And values for all the explanatory variables are available at that time. In other words, SR involves no assumptions on what the values will be for heating degree days, income, electricity price, and so on.

With respect to allocation of risks between a utility and its customers, statistical recoupling is like existing regulation. The utility, under SR, retains the risks associated with changes in sales and revenues caused by changes in all the variables included in the SR model. For example, if the model includes heating degree days as an explanatory variable, then the company's allowed revenues will change according to changes in actual heating degree days. If the winter is especially mild, the value for heating degree days will be lower than normal. This lower value will then, through the SR model, cut allowed revenues. Unlike other decoupling approaches, this one adjusts the revenues for fixed-cost recovery to vary with changes in the weather, local economy, and any other factors explicitly included in the models. This conclusion assumes that the statistical model(s) will accurately capture the effects of changes in weather, the economy, and electricity price on electricity use.

STATISTICAL RECOUPLING MODELS

DATA

I obtained data from five utilities to use in testing statistical recoupling (Table 2). Two of the utilities provided monthly data (New England Electric System's Massachusetts Electric Company subsidiary and Nevada Power Company), while the other three provided quarterly data (PacifiCorp's Utah service area, Public Service Company of Colorado, and Southern California Edison). All five utilities provided 13 or more years of data for their residential, commercial, and industrial customer classes. The utilities also provided data on heating and cooling degree days, average electricity prices for each customer class, and various measures of economic activity in their service areas. The price variable used in all these SR models is the ratio of revenues to sales; it does not explicitly treat the tariff details (i.e., monthly customer charge, energy charges, and demand charges).

MODEL RESULTS

In developing SR models, I emphasized simplicity rather than accuracy. So, I estimated only linear models (i.e., I ignored the possibility that log-log or log-linear models might perform better) and I used the minimum number of variables that seemed reasonable.[*] In particular, I used no binary (dummy) variables, as did the five utilities in their estimation of statistical models. For example, Nevada Power used binary variables for each month in combination with the cooling degree day variable to allow for differences in the amounts of electricity used for air conditioning by month. Other utilities used binary variables to reflect unusual weather or economic conditions (e.g., a strike). Finally, I used no lagged dependent variables (e.g., last quarter's electricity use) as explanatory variables; to do so would recouple revenues to sales.

To begin, I used the data from PSCo to construct two sets of statistical models.[#] One set dealt with each customer class separately, while the second set dealt with total sales. In each case, I used the data through 1989 to estimate the statistical models. I then used the last three years (1990, 1991, and 1992) to see how well the models performed.

---

[*]The models include terms that correct for autocorrelation, a common problem with time-series models. Autocorrelation refers to correlations among the error terms in a statistical model. Failure to correct for autocorrelation leads to higher standard errors for the model coefficients.

[#]I used *Forecast Pro for DOS* to estimate the models presented here (Stellwagen and Goodrich 1993).

Table 2. Customer classes and data from five utilities

Customer classes	Independent variables[a]
Nevada Power (monthly data, 1981-1992): residential, general service, large general service, hotel	Fraction of apartments in Clark County
New England Electric (monthly data, 1980-1992): residential electric heat, nonelectric heat, master-metered; commercial; industrial	Disposable income, personal income, employment (nonmanufacturing and manufacturing), wholesale production index
PacifiCorp — Utah (quarterly data, 1978-1992): residential, commercial, all industrial, four largest industrial customers	Income, employment (manufacturing, mining, total), industrial output
Public Service Company of Colorado (quarterly data, 1970-1992): residential, commercial, industrial	Income, employment
Southern California Edison (quarterly data, 1980-1992): residential, commercial, industrial	Income, employment (manufacturing and nonmanufacturing), unemployment rate, gross state product

[a]All the utilities sent data on electricity sales, number of customers, revenues, and price for each customer class, as well as data on heating and cooling degree days.

Sources: Farina (1993), Southern California Edison (1993), Tamashiro (1993), Wharton (1993), and Wordley (1993).

I used two criteria to assess the feasibility of applying SR to PSCo. First, I looked at the statistical properties of the model to see how well it did in simulating the past. Second, I looked at the changes in electricity prices that SR would have caused for the last three years (1990 through 1992).

The class-specific models had good statistical properties. The models all explained 93% or more of the quarterly variation in electricity use for each customer class. (Such high values for R^2 are typical of time-series models.) In addition, the coefficients of each variable always had the expected sign. As examples, the coefficients for heating and cooling degree days were both positive, and the coefficient for electricity price was negative. The coefficients for heating and cooling degree days were statistically significant at the 99% level, while the coefficients for electricity price and income were often significant at only the 80 to 90% level.

In terms of their ability to simulate correctly electricity use for 1990, 1991, and 1992 the models' performances were also good. The residential model had errors of -1.5, -2.4, and -2.8% for these three years. The commercial model had errors of -1.6, -3.1, and -2.5%. And the industrial model had errors of +1.3, +2.2, and +1.8%. The combined effect of these simulations, when weighted by the contribution of each sector to total retail revenues, was quite good. As shown in the top part of Table 3, the three models together had combined errors of -1.2%, -2.2%, and -2.1% for 1990, 1991, and 1992.

The aggregate model of total electricity use combines data from the residential, commercial, and industrial sectors. Thus, electricity use and the number of customers represent the totals across the three sectors, and electricity price is the ratio of total revenues to total sales across the three sectors. This model had much better statistical properties and an even more accurate simulation record than did the three sector-specific models (Fig. 5). This model had errors of -0.5%, 0.0%, and +1.1% for the three years. And the aggregate model of total electricity use per customer had errors of +0.2%, +1.4%, and +0.8% for 1990, 1991, and 1992. The aggregate model of electricity use is the simplest, has the best statistical properties, and yields the smallest errors. For the three years 1990 through 1992, SR based on this model had an average error of only 0.2%/year. If statistical recoupling had been in place in Colorado, it would have led to a 0.3% price decrease in 1990, no price change in 1991, and a 0.6% price increase in 1992.

I developed similar statistical models with the data from the other four utilities; the results are similar to the PSCo results. For example, I conducted the same type of analysis described above with monthly data from Nevada Power (bottom part of Table 3). The combined results, across the three primary customer classes, had errors slightly larger than those obtained with the PSCo models. The aggregate models had smaller errors than the combination of class models, consistent with the PSCo results.

Table 3. Percentage error in PSCo and NPC retail electricity sales had statistical recoupling been used in 1990, 1991, and 1992

	Combination of class models	Total sales	Total sales per customer
	Public Service Company of Colorado		
1990	-1.2	-0.5	+0.2
1991	-2.2	0.0	+1.4
1992	-2.1	+1.1	+0.8
	Nevada Power Company		
1990	-1.8	-1.8	-1.9
1991	-1.8	-0.4	-0.7
1992	-2.3	-0.2	-0.5

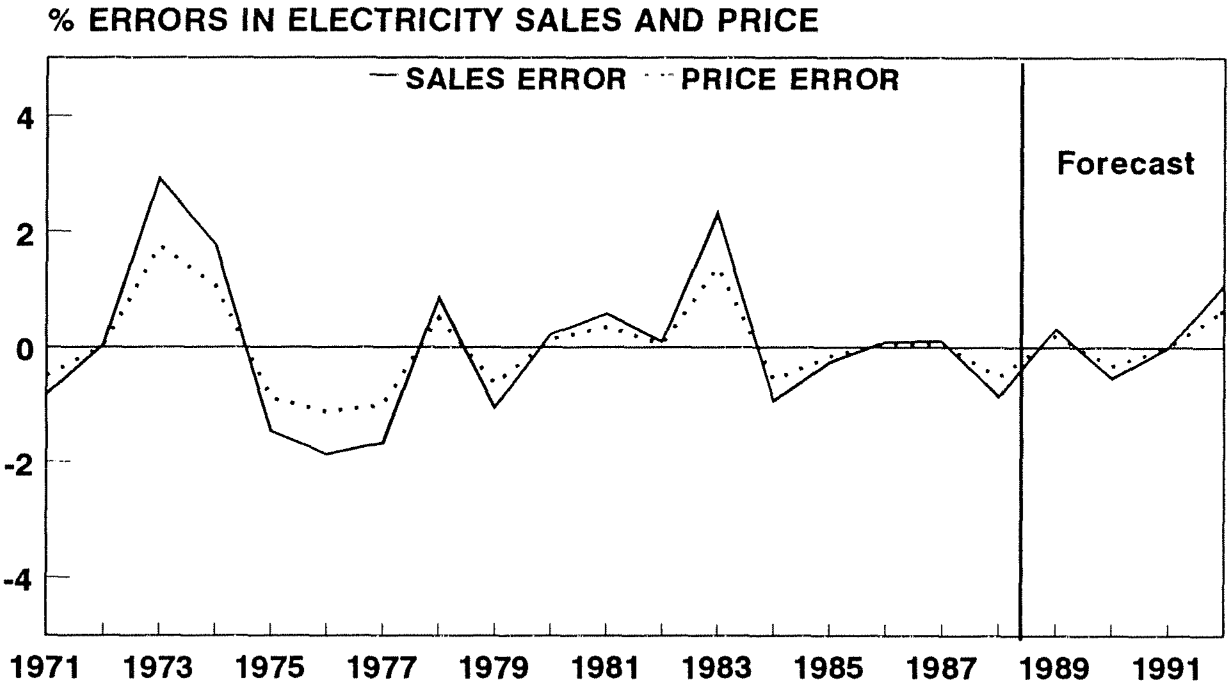

Fig. 5. **The errors in retail electricity sales and prices associated with statistical recoupling, based on the model of aggregate electricity use for PSCo. The errors in price equal 52% of the errors in sales.**

Figure 6 shows the performance of the SR models for each of the five utilities.* All these models used total electricity use (GWh) as the dependent variable in a simple linear equation with about six independent variables. With one exception (1992 for SCE), the errors are all less than 2%. And the three-year average error for each utility is less than 1%, except for SCE, which has a three-year error of -1.3%. The 15 data points in Fig. 6 show no pattern, either across utilities or with time. This lack of a pattern is encouraging because it suggests that the errors associated with SR are largely random and that, on average, the price changes caused by SR will approach zero.

These analyses of data from five utilities showed great similarity in results. This regularity suggests that SR is likely to yield consistent results from year to year and from utility to utility.

*The percentage change in electricity price associated with SR would be 25 to 50% lower than the percentage change in electricity sales, as discussed above.

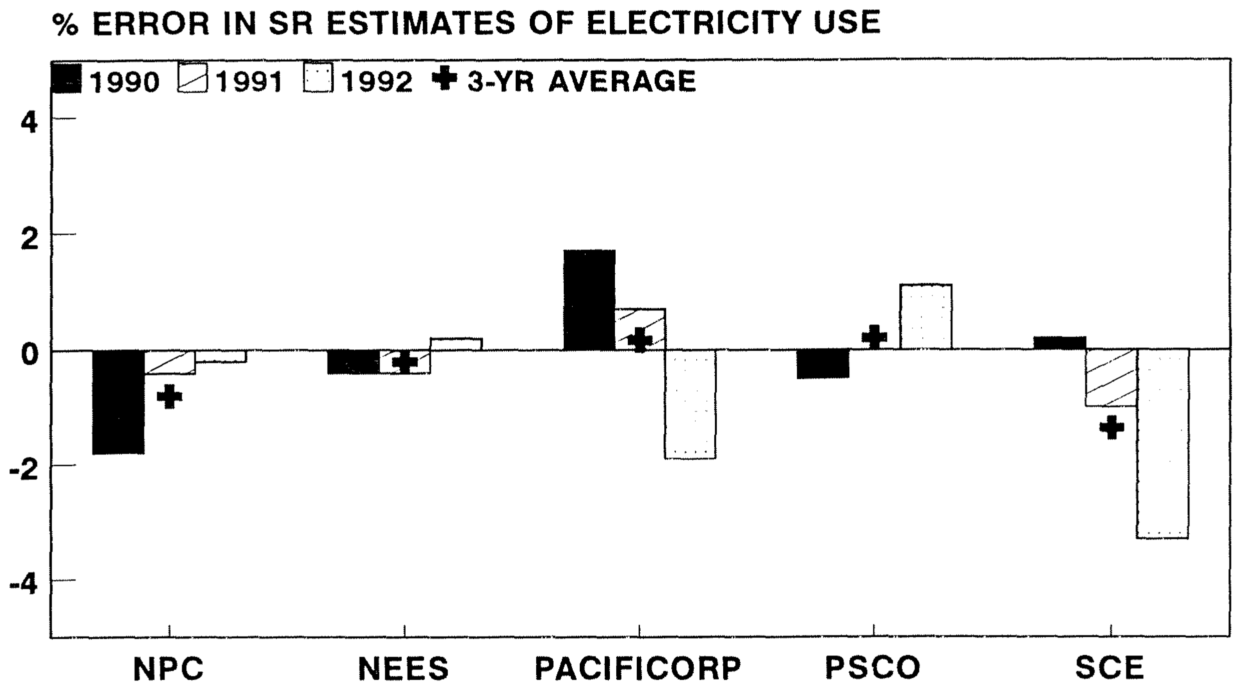

Fig. 6. **Errors in SR estimates of total (residential plus commercial plus industrial) electricity use for 1990, 1991, and 1992.**

NUMBER OF OBSERVATIONS NEEDED

An important issue associated with SR is the minimum number of observations needed to obtain reliable and stable estimates of electricity use during the simulation period. To examine this issue, I used the monthly data from NEES, which covers 1980 through 1992. I tested models of total electricity use (residential, commercial, and industrial) with eight, seven, six, five, four, and three years of data (i.e., with 96 to 36 observations). These models all included an autocorrelation term with a 12-month lag, which is why the first year of data (1980) was not available. The last three years of data (1990 through 1992) were not used in the estimation so that they could be used in a simulation test.

Table 4 summarizes the results for these six models. Each model had the same explanatory variables: number of customers, heating degree days, cooling degree days, average electricity price, and industrial production.

All the models, even the one with only 36 observations had very high explanatory power, with R^2 values of 97% or higher. The coefficients for number of customers, heating degree days, and cooling degree days were significant at the 100% level for every model. However, the coefficients for electricity price and industrial production were less significant for the models with fewer observations. Even here, however, the coefficients were significant

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at the 95% level or better for all the models with 60 or more observations. These two coefficients were not significant in the models with 36 or 48 observations.

Table 4. Statistical properties and performance of models of total electricity use for NEES retail customers

	Number of observations in model					
	96	84	72	60	48	36
Adjusted R^2	0.989	0.988	0.986	0.985	0.978	0.972
Significance of coefficients						
Number of customers	1.00	1.00	1.00	1.00	1.00	1.00
Heating degree days	1.00	1.00	1.00	1.00	1.00	1.00
Cooling degree days	1.00	1.00	1.00	1.00	1.00	1.00
Electricity price	0.99	0.95	0.97	0.98	0.89	0.82
Industrial production	1.00	1.00	1.00	0.98	0.77	0.30
Total error in simulation period, 1990 to 1992 (%)	+1.2	+0.9	-1.0	+0.5	+1.5	+4.8

The magnitudes of the coefficients for number of customers, heating degree days, and cooling degree days were quite stable across these models. The maximum variation across these three variables and six models was 15%. The variation in the magnitudes of the coefficients for electricity price and industrial production were higher. To illustrate, the electricity price coefficient in the model with 60 observations was 36% higher than the coefficient in the model with 96 observations.

Figure 7 shows the simulation performance of these six models for the years 1990, 1991, and 1992. All the models, except the one with only 36 observations, gave accurate estimates of total electricity use. These five models also gave consistent estimates from year to year: a slight underestimate of 1990 electricity use (-0.5%), a slight overestimate in 1991 (+0.4%), and a larger overestimate in 1992 (+0.7%).

I conducted a similar experiment with a utility that provided quarterly data rather than monthly data. The results, using PSCo data, are essentially the same (Table 5). As the number of observations used to estimate the model increases, the simulation accuracy also increases. For example, the model with 73 observations had a smaller three-year error (0.5%) than did any of the models with fewer observations; the same is true for the model with 65 observations, and so on.

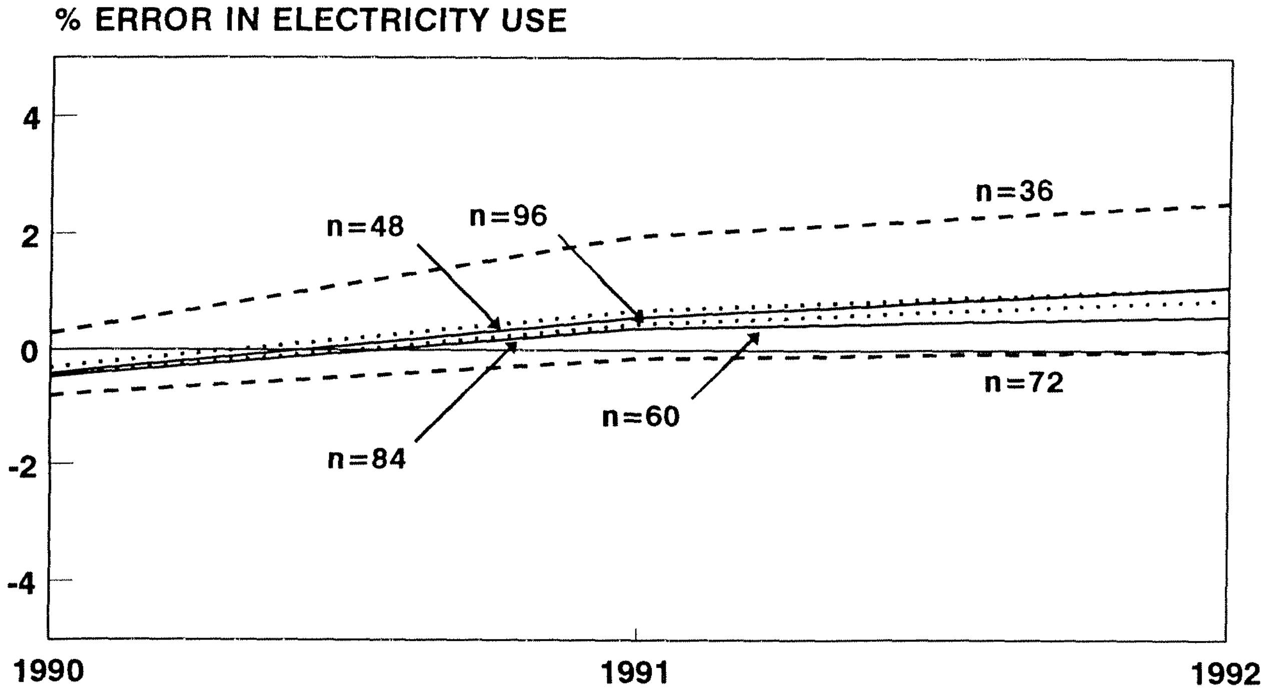

Fig. 7. Simulation results obtained with six models (with 36 to 96 observations) of total retail electricity use for NEES.

Table 5. Statistical properties and performance of models of total electricity use for PSCo retail customers

	Number of observations in model					
	73	65	57	49	41	33
Adjusted R^2	0.992	0.990	0.988	0.983	0.976	0.970
Significance of coefficients						
Number of customers	1.00	1.00	1.00	1.00	1.00	1.00
Heating degree days	1.00	1.00	1.00	1.00	1.00	1.00
Cooling degree days	1.00	1.00	1.00	1.00	1.00	1.00
Electricity price	0.94	0.90	0.98	0.99	0.95	0.75
Income	0.99	1.00	1.00	1.00	1.00	0.98
Total error in simulation period, 1990 to 1992 (%)	+0.5	+1.3	+2.7	+3.9	+4.5	+5.3

Generally speaking, the more observations used to estimate the model, the more accurate it is over the simulation period. However, over a broad range of sample sizes (above 40 or so), the results are quite stable in terms of both model estimation (explanatory power and statistical significance of the coefficients) and simulation (accuracy of predictions). Also, the range in model estimates increases from 1990 to 1991 and again to 1992.

IMPLEMENTING STATISTICAL RECOUPLING

Implementation involves two steps. In the first step, the utility, working with other interested parties, develops alternative statistical models. After review of these models, the company and other parties agree on a particular model to use, subject to approval by the PUC. For purposes of this example, I use the PacifiCorp quarterly data from 1978 through 1989 on electricity sales and its key determinants.* Aggregation of the data across the three primary classes (residential, commercial, and industrial) yields the following "preferred" model (Table 6):

Total electricity use (GWh/quarter) = -564 (CONST)
+ 0.00660 * Number of customers (CTOT)
+ 0.113 * Heating degree days (HDD)
+ 0.347 * Cooling degree days (CDD)
- 61.7 * Retail electricity price (PTOT)
+ 177 * Industrial output (INDOUT)

Table 6. Statistical properties for model of PacifiCorp total Utah sales (GWh/quarter)[a]

Term	Coefficient	Standard error	t-statistic	Significance
CTOT	0.006603	0.001354	4.875088	0.999982
PTOT	-61.723168	31.555730	-1.956005	0.942527
HDD	0.113035	0.013195	8.566718	1.000000
CDD	0.346906	0.035360	9.810710	1.000000
INDOUT	176.921646	111.595417	1.585385	0.879246
_CONST	-563.573372	334.283099	-1.685916	0.900402
_AUTO[-1]	0.415613	0.148275	2.802979	0.992229

Sample size 47	Number of parameters 7
Mean 2496	Standard deviation 326.9
R-square 0.968	Adjusted R-square 0.9632
Durbin-Watson 1.981	Ljung-Box(18)=19.99 P=0.6664
Forecast error 62.69	BIC 77.04
MAPE 0.01869	RMSE 57.83

[a]See the Appendix for an explanation of the statistical terms.

The second step involves application of the model to compute allowed sales and revenues for the years 1990, 1991, and 1992. Results for a case with no DSM programs are

*I did not use the data for 1990, 1991, and 1992 in estimating the statistical model; these data were used only to test the accuracy of the SR model in simulation.

shown in Table 7; see especially the last two lines of this table.* For 1990, based on actual values of heating and cooling degree days, industrial output, electricity price, and number of customers, the model computes allowed sales of 12,615 GWh, 1.7% more than the actual sales of 12,398. This yields an increase in electricity price of 0.05¢/kWh to be applied in 1991 to the base value of 5.36¢/kWh (the weighted average of the retail prices for each customer class approved in the most recent rate case). Thus, the average retail electricity price in 1991 is, as shown in Table 7, 5.41¢/kWh.

Table 7. Implementation of statistical recoupling in Utah with no DSM programs

	1990	1991	1992	1993	Three-year effect
Without statistical recoupling					
Gross sales (GWh)	12398	12839	13427		
DSM effect (GWh)	0	0	0		
Net sales (GWh)	12398	12839	13427		
Average retail price (¢/kWh)[a]	5.38	5.36	5.12	5.12	5.20
Revenues (million $)	667	688	687		1376
With statistical recoupling					
Actuals					
Average retail price (¢/kWh)	5.38	5.41	5.14	5.07	5.21
Revenues (million $)	667	695	690		1385
Heating degree days	5370	5795	5153		
Cooling degree days	1346	1102	1189		
Utah industrial output	11.2	11.3	11.8		
Real electricity price	4.68 1.[illegible]	4.47 1.210	4.16 1.236		
Number of customers (thousands)	491	502	506		
Allowed					
Sales (GWh)	12615	12925	13173		
Revenues (million $)	674 ?	691	680		1371
Price adjustment, next year					
¢/kWh	0.05	0.02	-0.05		0.02
% change	1.0	0.4	-1.0		0.33

[a]The year-to-year changes in average retail prices reflect the changes, both within and across customer classes, in the relative amounts of electricity used.

In 1991, the winter is more severe, the summer is milder, the number of customers grows, industrial output increases slightly, and electricity prices fall, leading to an increase in allowed sales, to 12,925 GWh. Actual sales grow also, to 12,839 GWh. This difference between actual and allowed sales in 1991 leads to a 0.02¢/kWh price increase to be applied to the base price in 1992.

*To produce the allowed sales estimates in Table 7, the coefficients in Table 6 for CTOT, PTOT, INDOUT, and CONST must be multiplied by 4 to convert from quarterly to annual estimates. Also, the autocorrelation term (AUTO[-1]) in Table 6 is set to zero for simulation.

In 1992, allowed sales are slightly below actual sales, leading to a 0.05¢/kWh price decrease applied in 1993. During this three-year period, SR would have increased prices slightly for two years and then decreased prices slightly in the third year. The overall effect is an increase in electricity price of 0.02¢/kWh (0.33%) for the three years. The percentage changes in electricity price are less than two-thirds the percentage errors in the SR model because of the adjustments in going from the retail electricity price to P_f. A typical residential customer with a base price of, say, 6.0¢/kWh would have paid 6.05¢/kWh, 6.02¢/kWh, and 5.95¢/kWh for electricity in 1991, 1992, and 1993 had SR been in place.

Table 8. Implementation of statistical recoupling in Utah with DSM programs

	1990	1991	1992	1993	Three-year effect
Without statistical recoupling					
Gross sales (GWh)	12398	12839	13427		
DSM effect (GWh)	-60	-120	-180		
Net sales (GWh)	12338	12719	13247		
Average retail price (¢/kWh)[a]	5.38	5.36	5.12	5.12	5.20
Revenues (million $)	664	682	678		1360
With statistical recoupling					
Actuals					
Average retail price (¢/kWh)	5.38	5.43	5.17	5.10	5.23
Revenues (million $)	664	690	685		1375
Allowed					
Sales (GWh)	12615	12925	13173		
Revenues (million $)	672	688	676		1364
Price adjustment, next year					
¢/kWh	0.07	0.05	-0.02		0.10
% change	1.3	0.9	-0.3		1.86

[a]To keep this example simple, these prices do not reflect recovery of DSM-program costs.

If PacifiCorp had run DSM programs that cut electricity use during this period, the mechanics of implementing SR would have been unchanged. In this example, I assume that the company's DSM programs cut electricity use by an incremental 0.5% each year (Table 8). In 1992, sales are lower by almost 1.5%.

Because of the company's assumed DSM programs, the price decreases are slightly smaller and the price increases are slightly larger than was the case with no DSM programs. During the three-year period, prices increase an average of 0.1%/year without DSM programs and 0.6%/year with DSM programs.* Thus, SR works as expected: it yields only

*These DSM-induced short-term price increases are offset by price decreases later on and by lower total costs of meeting electric-energy service needs.

small changes in electricity price and it removes the disincentive for PacifiCorp DSM programs.

This example covers a three-year implementation period, which, I believe, is appropriate. Retention of the same model for several years is administratively simple because it avoids conflict over model form and variables. However, the forecasts made with a statistical model will become less accurate as time goes on. On the other hand, estimating new models every year invites regulatory complications and, more important, is probably not necessary to maintain accuracy. Although SR can be implemented and updated as part of a regular rate-case cycle (e.g., the three-year cycles in California and New York), the method can be implemented and updated independent of rate cases.

Attachment C

Executive Summary – *Small Is Profitable*

This book describes 207 ways in which the size of "electrical resources" – devices that make, save, or store electricity – affects their economic value. It finds that properly considering the economic benefits of "distributed" (decentralized) electrical resources typically raises their value by a large factor, often approximately tenfold, by improving system planning, utility construction and operation (especially of the grid), and service quality, and by avoiding societal costs.

The actual increase in value, of course, depends strongly on the case-by-case technology, site, and timing. These factors are so complex that the distribution of value increases across the universe of potential applications is unknown. However, in many if not most cases, the increase in value should change investment decisions. For example, it should normally far exceed the cost differences between, say, modern natural-gas-fired power plants and windfarms. In many applications it could even make grid-interactive photovoltaics (solar cells) cost-effective today. It should therefore change how distributed resources are marketed and used, and it reveals policy and business opportunities to make these huge benefits explicit in the marketplace.

The electricity industry is in the midst of profound and comprehensive change, including a return to the local and neighborhood scale in which the industry's early history is rooted. Through the twentieth century, thermal (steam-raising) power stations evolved from local combined-heat-and-power plants serving neighborhoods to huge, remote, electricity-only generators serving whole regions. Elaborate technical and social systems commanded the flow of electrons from central stations to dispersed users and the reverse flow of money to pay for power stations, fuel, and grid. This architecture made sense in the early twentieth century when power stations were more expensive and less reliable than the grid, so they had to be combined via the grid to ensure reliable and economical supply. The grid also melded the diverse loads of many customers, shared the costly generating capacity, and made big and urban customers subsidize extension of electric service to rural customers.

By the start of the twenty-first century, however, virtually everyone in industrialized countries had electric service, and the basic assumptions underpinning the big-station logic had reversed. Central thermal power plants could no longer deliver competitively cheap and reliable electricity through the grid, because the plants had come to cost less than the grid and had become so reliable that nearly all power failures originated in the grid. Thus the grid linking central stations to remote customers had become the main driver of those customers' power costs and power-quality problems – which became more acute as digital equipment required extremely reliable electricity. The cheapest, most reliable power, therefore, was that which was produced at or near the customers.

Utilities' traditional focus on a few genuine economies of scale (the bigger, the less investment per kW) overlooked larger diseconomies of scale in the power stations, the grid, the way both are run, and the architecture of the entire system. The narrow vision that bigger is better ended up raising the costs and financial risks that it was meant to reduce. The resulting disadvantages are rooted in an enormous difference of scale between most needs and most supplies. Three-fourths of U.S. residential and commercial customers use electricity at an average rate that does not exceed 1.5 and 12 kilowatts respectively, whereas a single conventional central power plant produces about a million kilowatts. Resources better matched to the kilowatt scale of most customers' needs, or to the tens-of-thousands-of-kilowatts scale of typical distribution substations, or to an intermediate "microgrid" scale, thus became able to offer important but little-known economic advantages over the giant plants.

The capital markets have gradually come to realize this. Central thermal power plants stopped getting more efficient in the 1960s, bigger in the '70s, cheaper in the '80s, and bought in the '90s. Smaller units offered greater economies from mass-production than big ones could gain through unit size. In the '90s, the cost differences between giant nuclear plants – the last gasp of '70s and '80s gigantism – and railcar-deliverable combined-cycle gas-fired plants, derived from mass-produced aircraft engines, created political stresses that drove the restructuring of the industry. At the same time, new kinds of "micropower" generators thousands or tens of thousands of times smaller – microturbines, solar cells, fuel cells, wind turbines – started to become serious competitors, often enabled by information and telecommunications technologies. The restructured industry exposed the previously sheltered power-plant builders to brutal market discipline. Competition from micropower, uncertain demand, and the inflexibility of big, slow-to-build plants created financial risk well beyond the capital markets' appetite. Then in 2001, longstanding concerns about the inherent vulnerability of giant plants and the far-flung grid were reinforced by the 9/11 terrorist attacks.

The disappointing cost, efficiency, financial risk, and reliability of large thermal stations (and their associated grid investments) were leading their orders to collapse even before the cost difference between nuclear and combined-cycle costs stimulated restructuring that began to delaminate utilities. That restructuring created new market entrants, unbundled prices, and increased opportunities for competition at all scales – and thus launched the revolution in which swarms of microgenerators began to displace the behemoths. Already, distributed resources and the markets that let them compete have shifted most new generating units in competitive market economies from the million-kilowatt scale of the 1980s to the hundredfold-smaller scale that prevailed in the 1940s. Even more radical decentralization, all the way to customers' kilowatt scale (prevalent in and before the 1920s), is rapidly emerging and may prove even more beneficial, especially if it comes to rely on widely distributed microelectronic intelligence. Distributed generators do not require restructured electricity markets, and do not imply any particular scale for electricity business enterprises, but they are starting to drive the evolution of both.

Some distributed technologies like solar cells and fuel cells are still made in low volume and can therefore cost more than competing sources. But such distributed sources' increased value – due to improvements in financial risk, engineering flexibility, security, environmental quality, and other important attributes – can often more than offset their apparent cost disadvantage. This book introduces engineering and financial practitioners, business managers and strategists, public policymakers, designers, and interested citizens to those new value opportunities. It also provides a basic introduction to key concepts from such disciplines as electrical engineering, power system planning, and financial economics. Its examples are mainly U.S.-based, but its scope is global.

A handful of pioneering utilities and industries confirmed in the 1990s that distributed benefits are commercially valuable – so valuable that since the mid-'90s, most of the best conceptual analyses and field data have become proprietary, and government efforts to publish methods and examples of distributed-benefit valuation have been largely disbanded. Most published analyses and models, too, cover only small subsets of the issues. This study therefore seeks to provide the first full and systematic, if preliminary, public synthesis of how making electrical resources the right size can minimize their costs and risks. Its main findings are:

- The most valuable distributed benefits typically flow from financial economics – the lower risk of smaller modules with shorter lead times, portability, and low or no fuel-price volatility. These benefits often raise value by most of an order of magnitude (factor of ten) for renewables, and by about 3–5-fold for nonrenewables.
- Electrical-engineering benefits – lower grid costs and losses, better fault management, reactive support, etc. – usually provide another ~2–3-fold value gain, but more if the distribution grid is congested or if premium power quality or reliability are required.
- Many miscellaneous benefits may together increase value by another ~2-fold – more where waste heat can be reused.
- Externalities, though hard to quantify, may be politically decisive, and some are monetized.
- Capturing distributed benefits requires astute business strategy and reformed public policy.

Emerging electricity market structures can now provide the incentives, the measurement and validation, and the disciplinary perspectives needed to give distributed benefits a market voice. Successful competitors will reflect those benefits in investment decisions and prices. Nearly a dozen other technological, conceptual, and institutional forces are also driving a rapid shift toward the "distributed utility," where power generation migrates from remote plants to customers' back yards, basements, rooftops, and driveways. This transformation promises a vibrantly competitive, resilient, and lucrative electricity sector, at less cost to customers and to the earth – thus fulfilling Thomas Edison's original decentralized vision, just a century late.

Attachment D

207 Economic Benefits of Small Distributed Generation Resources

From the book, *Small Is Profitable*, by Amory Lovins, et al., Rocky Mountain Institute.

1) Distributed resources' generally shorter construction period leaves less time for reality to diverge from expectations, thus reducing the probability and hence the financial risk of under- or overbuilding.

2) Distributed resources' smaller unit size also reduces the consequences of such divergence and hence reduces its financial risk.

3) The frequent correlation between distributed resources' shorter lead time and smaller unit size can create a multiplicative, not merely an additive, risk reduction.

4) Shorter lead time further reduces forecasting errors and associated financial risks by reducing errors' amplification with the passage of time.

5) Even if short-lead-time units have lower thermal efficiency, their lower capital and interest costs can often offset the excess carrying charges on idle centralized capacity whose better thermal efficiency is more than offset by high capital cost.

6) Smaller, faster modules can be built on a "pay-as-you-go" basis with less financial strain, reducing the builder's financial risk and hence cost of capital.

7) Centralized capacity additions overshoot demand (absent gross underforecasting or exactly predictable step-function increments of demand) because their inherent "lumpiness" leaves substantial increments of capacity idle until demand can "grow into it." In contrast, smaller units can more exactly match gradual changes in

demand without building unnecessary slack capacity ("build-as-you-need"), so their capacity additions are employed incrementally and immediately.

8) Smaller, more modular capacity not only ties up less idle capital (#7), but also does so for a shorter time (because the demand can "grow into" the added capacity sooner), thus reducing the cost of capital per unit of revenue.

9) If distributed resources are becoming cheaper with time, as most are, their small units and short lead times permit those cost reductions to be almost fully captured. This is the inverse of #8: revenue increases there, and cost reductions here, are captured incrementally and immediately by following the demand or cost curves nearly exactly.

10) Using short-lead-time plants reduces the risk of a "death spiral" of rising tariffs and stagnating demand.

11) Shorter lead time and smaller unit size both reduce the accumulation of interest during construction – an important benefit in both accounting and cashflow terms.

12) Where the multiplicative effect of faster-and-smaller units reduces financial risk (#3) and hence the cost of project capital, the correlated effects—of that cheaper capital, less of it (#11), and needing it over a shorter construction period (#11)—can be triply multiplicative. This can in turn improve the enterprise's financial performance, gaining it access to still cheaper capital. This is the opposite of the effect often observed with large-scale, long-lead-time projects, whose enhanced financial risks not only raise the cost of project capital but may cause general deterioration of the developer's financial indicators, raising its cost of capital and making it even less competitive.

13) For utilities that use such accrual accounting mechanisms as AFUDC (Allowance for Funds Used During Construction), shorter lead time's reduced absolute and fractional interest burden can improve the quality of earnings, hence investors' perceptions and willingness to invest.

14) Distributed resources' modularity increases the developer's financial freedom by tying up only enough working capital to complete one segment at a time.

15) Shorter lead time and smaller unit size both decrease construction's burden on the developer's cashflow, improving financial indicators and hence reducing the cost of capital.

16) Shorter-lead-time plants can also improve cashflow by starting to earn revenue sooner—through operational revenue-earning or regulatory rate-basing as soon as each module is built—rather than waiting for the entire total capacity to be completed.

17) The high velocity of capital (#16) may permit self-financing of subsequent units from early operating revenues.

18) Where external finance is required, early operation of an initial unit gives investors an early demonstration of the developer's capability, reducing the perceived risk of subsequent units and hence the cost of capital to build them.

19) Short lead time allows companies a longer "breathing spell" after the startup of each generating unit, so that they can better recover from the financial strain of construction.

20) Shorter lead time and smaller unit size may decrease the incentive, and the bargaining power, of some workers or unions whose critical skills may otherwise give them the leverage to demand extremely high wages or to stretch out construction still

further on large, lumpy, long-lead-time projects that can yield no revenue until completed.

21) Smaller plants' lower local impacts may qualify them for regulatory exemptions or streamlined approvals processes, further reducing construction time and hence financing costs.

22) Where smaller plants' lower local impacts qualify them for regulatory exemptions or streamlined approvals processes, the risk of project failure and lost investment due to regulatory rejection or onerous condition decreases, so investors may demand a smaller risk premium.

23) Smaller plants have less obtrusive siting impacts, avoiding the risk of a vicious circle of public response that makes siting ever more difficult.

24) Small units with short lead times reduce the risk of buying a technology that is or becomes obsolete even before it's installed, or soon thereafter.

25) Smaller units with short development and production times and quick installation can better exploit rapid learning: many generations of product development can be compressed into the time it would take simply to build a single giant unit, let alone operate it and gain experience with it.

26) Lessons learned during that rapid evolution can be applied incrementally and immediately in current production, not filed away for the next huge plant a decade or two later.

27) Distributed resources move labor from field worksites, where productivity gains are sparse, to the factory, where they're huge.

28) Distributed resources' construction tends to be far simpler, not requiring an expensively scarce level of construction management talent.

29) Faster construction means less workforce turnover, less retraining, and more craft and management continuity than would be possible on a decade-long project.

30) Distributed resources exploit modern and agile manufacturing techniques, highly competitive innovation, standardized parts, and commonly available production equipment shared with many other industries. All of these tend to reduce costs and delays.

31) Shorter lead time reduces exposure to changes in regulatory rules during construction.

32) Technologies that can be built quickly before the rules change and are modular so they can "learn faster" and embody continuous improvement are less exposed to regulatory risks.

33) Distributed technologies that are inherently benign (renewables) are less likely to suffer from regulatory restrictions.

34) Distributed resources may be small enough per unit to be considered de minimis and avoid certain kinds of regulation.

35) Smaller, faster modules offer some risk-reducing degree of protection from interest-rate fluctuations, which could be considered a regulatory risk if attributed to the Federal Reserve or similar national monetary authorities.

36) The flexibility of distributed resources allows managers to adjust capital investments continuously and incrementally, more exactly tracking the unfolding future, with continuously available options for modification or exit to avoid trapped equity.

37) Small, short-lead-time resources incur less carrying-charge penalty if suspended to await better information, or even if abandoned.

38) Distributed resources typically offer greater flexibility in accelerating completion if this becomes a valuable outcome.

39) Distributed resources allow capacity expansion decisions to become more routine and hence lower in transaction costs and overheads.

40) Distributed generation allows more learning before deciding, and makes learning a continuous process as experience expands rather than episodic with each lumpy, all-or-nothing decision.

41) Smaller, shorter-lead-time, more modular units tend to offer cheaper and more flexible options to planners seeking to minimize regret, because such resources can better adapt to and more cheaply guard against uncertainty about how the future will unfold.

42) Modular plants have off-ramps so that stopping the project is not a total loss: value can still be recovered from whatever modules were completed before the stop.

43) Distributed resources' physical portability will typically achieve a higher expected value than an otherwise comparable non-portable resource, because if circumstances change, a portable resource can be physically redeployed to a more advantageous location.

44) Portability also merits a more favorable discount rate because it is less likely that the anticipated value will not be realized—even though it may be realized in a different location than originally expected.

45) A service provider or third-party contractor whose market reflects a diverse range of temporary or uncertain-duration service needs can maintain a "lending library"

of portable distributed resources that can achieve high collective utilization, yet at each deployment avoid inflexible fixed investments that lack assurance of long-term revenue.

46) Modular, standardized, distributed, portable units can more readily be resold as commodities in a secondary market, so they have a higher residual or salvage value than corresponding monolithic, specialized, centralized, nonportable units that have mainly a demolition cost at the end of their useful lives.

47) The value of the resale option for distributed resources is further enhanced by their divisibility into modules, of which as many as desired may be resold and the rest retained to a degree closely matched to new needs.

48) Distributed resources typically do little or no damage to their sites, and hence minimize or avoid site remediation costs if redeployed, salvaged, or decommissioned.

49) Volatile fuel prices set by fluctuating market conditions represent a financial risk. Many distributed resources do not use fuels and thus avoid that costly risk.

50) Even distributed resources that do use fuels, but use them more efficiently or dilute their cost impact by a higher ratio of fixed to variable costs, can reduce the financial risk of volatile fuel prices.

51) Resources with a low ratio of variable to fixed costs, such as renewables and end-use efficiency, incur less cost volatility and hence merit more favorable discount rates.

52) Fewer staff may be needed to manage and maintain distributed generation plants: contrary to the widespread assumption of higher per-capita overheads, the small organizations required can actually be leaner than large ones.

53) Meter-reading and other operational overheads may be quite different for renewable and distributed resources than for classical power plants.

54) Distributed resources tend to have lower administrative overheads than centralized ones because they do not require the same large organizations with broad capabilities nor, perhaps, more complex legally mandated administrative and reporting requirements.

55) Compared with central power stations, mass-produced modular resources should have lower maintenance equipment and training costs, lower carrying charges on spare-parts inventories, and much lower unit costs for spare parts made in higher production runs.

56) Unlike different fossil fuels, whose prices are highly correlated with each other, non-fueled resources (efficiency and renewables) have constant, uncorrelated prices that reduce the financial risk of an energy supply portfolio.

57) Efficiency and cogeneration can provide insurance against uncertainties in load growth because their output increases with electricity demand, providing extra capacity in exactly the conditions in which it is most valuable, both to the customer and to the electric service provider.

58) Distributed resources are typically sited at the downstream (customer) end of the traditional distribution system, where they can most directly improve the system's lowest load factors, worst losses, and highest marginal grid capital costs—thus creating the greatest value.

59) The more fine-grained the distributed resource—the closer it is in location and scale to customer load—the more exactly it can match the temporal and spatial pattern of the load, thus maximizing the avoidance of costs, losses, and idle capacity.

60) Distributed resources matched to customer loads can displace the least utilized grid assets.

61) Distributed resource matched to customer loads can displace the part of the grid that has the highest losses.

62) Distributed resources matched to customer loads can displace the part of the grid that typically has the biggest and costliest requirements for reactive power control.

63) Distributed resources matched to customer loads can displace the part of the grid that has the highest capital costs.

64) Many renewable resources closely fit traditional utility seasonal and daily loadshapes, maximizing their "capacity credit"—the extent to which each kW of renewable resource can reliably displace dispatchable generating resources and their associated grid capacity.

65) The same loadshape-matching enables certain renewable sources (such as photovoltaics in hot, sunny climates) to produce the most energy at the times when it is most valuable—an attribute that can be enhanced by design.

66) Reversible-fuel-cell storage of photovoltaic electricity can not only make the PVs a dispatchable electrical resource, but can also yield useful fuel-cell byproduct heat at night when it is most useful and when solar heat is least available.

67) Combinations of various renewable resources can complement each other under various weather conditions, increasing their collective reliability.

68) Distributed resources such as photovoltaics that are well matched to substation peak load can precool the transformer—even if peak load lasts longer than peak PV output—thus boosting substation capacity, reducing losses, and extending equipment life.

69) In general, interruptions of renewable energy flows due to weather can be predicted earlier and with higher confidence than interruptions of fossil-fueled or nuclear energy flows due to malfunction or other mishap.

70) Such weather-related interruptions of renewable sources also generally last for a much shorter time than major failures of central thermal stations.

71) Some distributed resources are the most reliable known sources of electricity, and in general, their technical availability is improving more and faster than that of centralized resources. (End-use efficiency resources are by definition 100% available—effectively, even more.)

72) Certain distributed generators' high technical availability is an inherent per-unit attribute—not achieved through the extra system costs of reserve margin, interconnection, dispersion, and unit and technological diversity required for less reliable central units to achieve the equivalent supply reliability.

73) In general, given reasonably reliable units, a large number of small units will have greater collective reliability than a small number of large units, thus favoring distributed resources.

74) Modular distributed generators have not only a higher collective availability but also a narrower potential range of availability than large, non-modular units, so there is less uncertainty in relying on their availability for planning purposes.

75) Most distributed resources, especially renewables, tend not only to fail less than centralized plants, but also to be easier and faster to fix when they do fail.

76) Repairs of distributed resources tend to require less exotic skills, unique parts, special equipment, difficult access, and awkward delivery logistics than repairs of centralized resources.

77) Repairs of distributed resources do not require costly, hard-to-find large blocks of replacement power, nor require them for long periods.

78) When a failed individual module, tracker, inverter, or turbine is being fixed, all the rest in the array continue to operate.

79) Distributed generation resources are quick and safe to work with: no post-shutdown thermal cooling of a huge thermal mass, let alone radioactive decay, need be waited out before repairs can begin.

80) Many distributed resources operate at low or ambient temperatures, fundamentally increasing safety and simplicity of repair.

81) A small amount of energy storage, or simple changes in design, can disproportionately increase the capacity credit due to intermittent renewable resources.

82) Distributed resources have an exceptionally high grid reliability value if they can be sited at or near the customer's premises, thus risking less "electron haul length" where supply could be interrupted.

83) Distributed resources tend to avoid the high voltages and currents and the complex delivery systems that are conducive to grid failures.

84) Deliberate disruptions of supply can be made local, brief, and unlikely if electric systems are carefully designed to be more efficient, diverse, dispersed, and renewable.

85) By blunting the effect of deliberate disruptions, distributed resources reduce the motivation to cause such disruptions in the first place.

86) Distributed generation in a large, far-flung grid may change its fundamental transient-response dynamics from unstable to stable—especially as the distributed resources become smaller, more widespread, faster-responding, and more intelligently controlled.

87) Modular, short-lead-time technologies valuably temporize: they buy time, in a self-reinforcing fashion, to develop and deploy better technologies, learn more, avoid more decisions, and make better decisions. The faster the technological and institutional change, and the greater the turbulence, the more valuable this time-buying ability becomes. The more the bought time is used to do things that buy still more time, the greater the leverage in avoided regret.

88) Smaller units, which are often distributed, tend to have a lower forced outage rate and a higher equivalent availability factor than larger units, thus decreasing reserve margin and spinning reserve requirements.

89) Multiple small units are far less likely to fail simultaneously than a single large unit.

90) The consequences of failure are far smaller for a small than for a large unit.

91) Smaller generating units have fewer and generally briefer scheduled or forced maintenance intervals, further reducing reserve requirements.

92) Distributed generators tend to have less extreme technical conditions (temperature, pressure, chemistry, etc.) than giant plants, so they tend not to incur the inherent reliability problems of more exotic materials pushed closer to their limits—thus increasing availability.

93) Smaller units tend to require less stringent technical reliability performance (e.g., failures per meter of boiler tubing per year) than very large units in order to achieve the same reliability (in this instance, because each small unit has fewer meters of boiler tubing)—thus again increasing unit availability and reducing reserves.

94) "Virtual spinning reserve" provided by distributed resources can replace traditional central-station spinning reserve at far lower cost.

95) Distributed substitutes for traditional spinning reserve capacity can reduce its operating hours—hence the mechanical wear, thermal stress, corrosion, and other gradual processes that shorten the life of expensive, slow-to-build, and hard-to-repair central generating equipment.

96) When distributed resources provide "virtual spinning reserve," they can reduce cycling, turn-on/shutdown, and low-load "idling" operation of central generating units, thereby increasing their lifetime.

97) Such life extension generally incurs a lower risk than supply expansion, and hence merits a more favorable risk-adjusted discount rate, further increasing its economic advantage.

98) Distributed resources can help reduce the reliability and capacity problems to which an aging or overstressed grid is liable.

99) Distributed resources offer greater business opportunities for profiting from hot spots and price spikes, because time and location-specific costs are typically more variable within the distribution system than in bulk generation.

100) Strategically, distributed resources make it possible to position and dispatch generating and demand-side resources optimally so as to maximize the entire range of distributed benefits.

101) Distributed resources (always on the demand side and often on the supply side) can largely or wholly avoid every category of grid costs on the margin by being already at or near the customer and hence requiring no further delivery.

102) Distributed resources have a shorter haul length from the more localized (less remote) source to the load, hence less electric resistance in the grid.

103) Distributed resources reduce required net inflow from the grid, reducing grid current and hence grid losses.

104) Distributed resources cause effective increases in conductor cross-section per unit of current (thereby decreasing resistance) if an unchanged conductor is carrying less current.

105) Distributed resources result in less conductor and transformer heating, hence less resistance.

106) Distributed resources' ability to decrease grid losses is increased because they are close to customers, maximizing the sequential compounding of the different losses that they avoid.

107) Distributed photovoltaics particularly reduce grid loss load because their output is greatest at peak hours (in a summer-peaking system), disproportionately reducing the heating of grid equipment.

108) Such onpeak generation also reduces losses precisely when the reductions are most valuable.

109) Since grid losses avoided by distributed resources are worth the product of the number times the value of each avoided kWh of losses, their value can multiply rapidly when using area- and time-specific costs.

110) Distributed resources can reduce reactive power consumption by shortening the electron haul length through lines and by not going through as many transformers—both major sources of inductive reactance.

111) Distributed resources can reduce current flows through inductive grid elements by meeting nearby loads directly rather than by bringing current through lines and transformers.

112) Some end-use-efficiency resources can provide reactive power as a free byproduct of their more efficient design.

113) Distributed generators that feed the grid through appropriately designed DC-to-AC inverters can provide the desired real-time mixture of real and reactive power to maximize value.

114) Reduced reactive current improves distribution voltage stability, thus improving end-use device reliability and lifetime, and enhancing customer satisfaction, at lower cost than for voltage-regulating equipment and its operation.

115) Reduced reactive current reduces conductor and transformer heating, improving grid components' lifetime.

116) Reduced reactive current, by cooling grid components, also makes them less likely to fail, improving the quality of customer service.

117) Reduced reactive current, by cooling grid components, also reduces conductor and transformer resistivity, thereby reducing real-power losses, hence reducing heating, hence further improving component lifetime and reliability.

118) Reduced reactive current increases available grid and generating capacity, adding to the capacity displacement achieved by distributed resources' supply of real current.

119) Distributed resources, by reducing line current, can help avoid voltage drop and associated costs by reducing the need for installing equipment to provide equivalent voltage support or step-up.

120) Distributed resources that operate in the daytime, when sunlight heats conductors or transformers, help to avoid costly increases in circuit voltage, reconductoring (replacing a conductor with one of higher ampacity), adding extra circuits, or, if available, transferring load to other circuits with spare ampacity.

121) Substation-sited photovoltaics can shade transformers, thereby improving their efficiency, capacity, lifetime, and reliability.

122) Distributed resources most readily replace distribution transformers at the smaller transformer sizes that have higher unit costs.

123) Distributed resources defer or avoid adding grid capacity.

124) Distributed resources, by reducing the current on transmission and distribution lines, free up grid capacity to provide service to other customers.

125) Distributed resources help "decongest" the grid so that existing but encumbered capacity can be freed up for other economic transactions.

126) Distributed resources avoid the siting problems that can occur when building new transmission lines.

127) These siting problems tend to be correlated with the presence of people, but people tend to correlate with both loads and opportunities for distributed resources.

128) Distributed resources' unloading, hence cooling, of grid components can disproportionately increase their operating life because most of the life-shortening effects are caused by the highest temperatures, which occur only during a small number of hours.

129) More reliable operation of distribution equipment can also decrease periodic maintenance costs and outage costs.

130) Distributed resources' reactive current, by improving voltage stability, can reduce tapchanger operation on transformers, increasing their lifetime.

131) Since distributed resources are nearer to the load, they increase reliability by reducing the length the power must travel and the number of components it must traverse.

132) Carefully sited distributed resources can substantially increase the distribution system operator's flexibility in rerouting power to isolate and bypass distribution faults and to maintain service to more customers during repairs.

133) That increased delivery flexibility reduces both the number of interrupted customers and the duration of their outage.

134) Distributed generators can be designed to operate properly when islanded, giving local distribution systems and customers the ability to ride out major or widespread outages.

135) Distributed resources require less equipment and fewer procedures to repair and maintain the generators.

136) Stand-alone distributed resources not connected to the grid avoid the cost (and potential ugliness) of extending and connecting a line to a customer's site.

137) Distributed resources can improve utility system reliability by powering vital protective functions of the grid even if its own power supply fails.

138) The modularity of many distributed resources enables them to scale down advantageously to small loads that would be uneconomic to serve with grid power because its fixed connection costs could not be amortized from electricity revenues.

139) Many distributed resources, notably photovoltaics, have costs that scale far more closely to their loads than do the costs of distribution systems.

140) Distributed generators provide electric energy that would otherwise have to be generated by a centralized plant, backed up by its spinning reserve, and delivered through grid losses to the same location.

141) Distributed resources available on peak can reduce the need for the costlier to-keep-warm centralized units.

142) Distributed resources very slightly reduce spinning reserves' operational cost.

143) Distributed resources can reduce power stations' startup cycles, thus improving their efficiency, lifetime, and reliability.

144) Inverter-driven distributed resources can provide extremely fast ramping to follow sudden increases or decreases in load, improving system stability and component lifetimes.

145) By combining fast ramping with flexible location, often in the distribution system, distributed resources may provide special benefits in correcting transients locally before they propagate upstream to affect more widespread transmission and generating resources.

146) Distributed resources allow for net metering, which in general is economically beneficial to the distribution utility (albeit at the expense of the incumbent generator).

147) Distributed resources may reduce utilities' avoided marginal cost and hence enable them to pay lower buyback prices to Qualifying Facilities.

148) Distributed resources' ability to provide power of the desired level of quality and reliability to particular customers—rather than just a homogeneous commodity via the grid—permits providers to match their offers with customers' diverse needs and to be paid for that close fit.

149) Distributed resources can avoid harmonic distortion in the locations where it is both more prevalent (e.g., at the end of long rural feeders) and more costly to correct.

150) Certain distributed resources can actively cancel harmonic distortion in real time, at or near the customer level.

151) Whether provided passively or actively, reduced harmonics means lower grid losses, equipment heating (which reduces life and reliability), interference with end-user and grid-control equipment, and cost of special harmonic-control equipment.

152) Appropriately designed distributed inverters can actively cancel or mitigate transients in real time at or near the customer level, improving grid stability.

153) Many distributed resources are renewable, and many customers are willing to pay a premium for electricity produced from a non-polluting generator.

154) Distributed resources allow for local control of generation, providing both economic-development and political benefits.

155) Certain distributed nonelectric supply-side resources such as daylighting and passive ventilation can valuably improve non-energy attributes (such as thermal, visual, and acoustic comfort), hence human and market performance.

156) Bundling distributed supply- with demand-side resources increases many of distributed generation's distributed benefits per kW, e.g., by improving match to loadshape, contribution to system reliability, or flexibility of dispatching real and reactive power.

157) Bundling distributed supply- with demand-side resources means less supply, improving the marketability of both by providing more benefits (such as security of supply) per unit of cost.

158) Bundling distributed supply- with demand-side resources increases the provider's profit or price flexibility by melding lower supply-side with higher demand-side margins.

159) Certain distributed resources can valuably burn local fuels that would otherwise be discarded, often at a financial and environmental cost.

160) Distributed resources provide a useful amount and temperature of waste heat conveniently close to the end-use.

161) Photovoltaic (or solar-thermal) panels on a building's roof can reduce the air conditioning load by shading the roof—thus avoiding air-conditioner and air-handling capacity, electricity, and the capacity to generate and deliver it, while extending roof life.

162) Some distributed resources like microturbines produce carbon dioxide, which can be used as an input to greenhouses or aquaculture farms.

163) Some types of distributed resources like photovoltaic tiles integrated into a roof can displace elements of the building's structure and hence of its construction cost.

164) Distributed resources make possible homes and other buildings with no infrastructure in the ground—no pipes or wires coming out—thus saving costs for society and possibly for the developer.

165) Because it lacks electricity, undeveloped land may be discounted in market value by more than the cost of installing distributed renewable generation—making that power source better than free.

166) Since certain distributed resources don't pollute and are often silent and inconspicuous, they usually don't reduce, and may enhance, the value of surrounding land—contrary to the effects of central power plants.

167) Some distributed resources can be installed on parcels of land that are too small, steep, rocky, odd-shaped, or constrained to be valuable for real-estate development.

168) Some distributed resources can be double-decked over other uses, reducing or eliminating net land costs. (Double-decking over utility substations, etc., can also yield valuable shading benefits that reduce losses (# 168) and extend equipment life.)

169) The shading achieved by double-decking PVs above parked cars or livestock can yield numerous private and public side-benefits.

170) Distributed resources may reduce society's subsidy payments compared with centralized resources.

171) Distributed resources can significantly—and when deployed on a large scale can comprehensively and profoundly—improve the resilience of electricity supply, thus reducing many kinds of social costs, risks, and anxieties, including military costs and vulnerabilities.

172) Technologies perceived as benign in their local impacts make siting approvals more likely, reducing the risk of project failure and lost investment and hence reducing the risk premium demanded by investors.

173) Technologies perceived as benign or de minimis in their local impacts can often also receive siting approvals faster, or can even be exempted from approvals processes, further shortening construction time and hence reducing financial cost and risk.

174) Technologies perceived as benign in their local impacts have wide flexibility in siting, making it possible to shop for lower-cost sites.

175) Technologies perceived as benign in their local impacts have wide flexibility in siting, making it easier to locate them in the positions that will maximize system benefits.

176) Siting flexibility is further increased where the technology, due to its small scale, cogeneration potential, and perhaps nonthermal nature, requires little or no heat sink.

177) Distributed resources' local siting and implementation tend to increase their local economic multiplier and thereby further enhance local acceptance.

178) Distributed resources can often be locally made, creating a concentration of new skills, industrial capabilities, and potential to exploit markets elsewhere.

179) Most well-designed distributed resources reduce acoustic and aesthetic impacts.

180) Distributed resources can reduce irreversible resource commitments and their inflexibility.

181) Distributed resources facilitate local stakeholder engagements and increase the community's sense of accountability, reducing potential conflict.

182) Distributed resources generally reduce and simplify public health and safety impacts, especially of the more opaque and lasting kinds.

183) Distributed resources are less liable to the regulatory "ratcheting" feedback that tends to raise unit costs as more plants are built and as they stimulate more public unease.

184) Distributed resources are fairer, and seen to be fairer, than centralized resources because their costs and benefits tend to go to the same people at the same time.

185) Distributed resources have less demanding institutional requirements, and tend to offer the political transparency and attractiveness of the vernacular.

186) Distributed resources lend themselves to local decisions, enhancing public comprehension and legitimacy.

187) Distributed resources are more likely than centralized ones to respect and fit community and jurisdictional boundaries, simplifying communications and decision-making.

188) Distributed resources better fit the scale of communities' needs and ability to address them.

189) Distributed resources foster institutional structure that is more weblike, learns faster, and is more adaptive, making the inevitable mistakes less likely, consequential, and lasting.

190) Distributed resources' smaller, more agile, less bureaucratized institutional framework is more permeable and friendly to information flows inward and outward, further speeding learning.

191) Distributed resources' low cost and short lead time for experimental improvement encourages and rewards more of it and hence accelerates it.

192) Distributed resources' size and technology (frequently well correlated) generally merit and enjoy a favorable public image that developers, in turn, are generally both eager and able to uphold and enhance, aligning their goals with the public's.

193) With some notable exceptions such as dirty engine generators, distributed resources tend to reduce total air emissions per unit of energy services delivered.

194) Since distributed resources' air emissions are directly experienced by the neighbors with the greatest influence on local acceptance and siting, political feedback is short and quick, yielding strong pressure for clean operations and continuous improvement.

195) Due to scale, technology, and local accountability informed by direct perception, the rules governing distributed resources are less likely to be distorted by special-interest lobbying than those governing centralized resources.

196) Distributed utilities tend to require less, and often require no, land for fuel extraction, processing, and transportation.

197) Distributed resources' land-use tends to be temporary rather than permanent.

198) Distributed resources tend to reduce harm to fish and wildlife by inherently lower impacts and more confined range of effects (so that organisms can more easily avoid or escape them).

199) Some distributed resources reduce and others altogether avoid harmful discharges of heat to the environment.

200) Some hydroelectric resources may be less harmful to fish at small than at large scale.

201) The greater operational flexibility of some distributed resources, and their ability to serve multiple roles or users, may create new opportunities for power exchange benefiting anadromous fish.

202) Well-designed distributed resources are often less materials- and energy-intensive than their centralized counterparts, comparing whole systems for equal delivered production.

203) Distributed resources' often lower materials and energy intensity reduces their indirect or embodied pollution from materials production and manufacturing.

204) Many distributed resources' reduced materials intensity reduces their indirect consumption of depletable mineral resources.

205) The small scale, standardization, and simplicity of most distributed resources simplifies their repair and may improve the likelihood of their remanufacture or recycling, further conserving materials.

206) Many distributed resources withdraw and consume little or no water.

207) Many distributed resources offer psychological or social benefits of almost infinite variety to users whose unique prerogative it is to value them however they choose.