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COMMISSION

SIERRA CLUB, CUMBERLAND CHAPTER

PSC CASE NO. 2006-00472
RESPONSES TO THE FIRST INFORMATION REQUEST OF EAST KY POWER COOP, INC.
DATED JULY 25, 2007

DATE SUBMITTED: AUGUST 8, 2007

APPALACHIAN CITIZENS LAW CENTER, INC.
207 W. COURT ST., SUITE 202
PRESTONSBURG, KENTUCKY 41653-7725
606-886-1442 1-800-919-1442
Fax 606-886-1455
www.appalachianlawcenter.org

GREG HOWARD
Staff Attorney

STEPHEN A. SANDERS
Director

WES ADDINGTON
Mine Safety Project Attorney

August 8, 2007

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 ten (10) copies of the responses of the Cumberland Chapter of the Sierra Club to the first data request of East Kentucky Power Cooperative, Inc. A copy of this document has been mailed to all parties listed on the attached Certificate of Service.

Sincerely,

Stephen A. Sanders
Director

SAS:dek
Enclosure as stated

cc: Parties of Record

CERTIFICATE OF SERVICE

I hereby certify that an original and ten copies of the foregoing responses to the first data request of East Kentucky Power Cooperative, Inc. to the Sierra Club 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 8th day of August, 2007.

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

Hon. Michael L. Kurtz
Attorney at Law
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, OH 45202- 4434

Hon. Charles A. Lile
Senior Corporate Counsel
East Kentucky Power Cooperative, Inc.
4775 Lexington Road
P.O. Box 707
Winchester, KY 40392-0707

Stephen A. Sanders

Stephen A. Sanders,
COUNSEL FOR THE SIERRA CLUB

APPALACHIAN CITIZENS LAW CENTER, INC.
207 W. COURT ST., SUITE 202
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Fax 606-886-1455
www.appalachianlawcenter.org

GREG HOWARD
Staff Attorney

STEPHEN A. SANDERS
Director

WES ADDINGTON
Mine Safety Project Attorney

August 8, 2007

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

RE: Case No. 2006-00472

Dear Mr. Lile:

Please find enclosed a copy of the responses of the Cumberland Chapter of the Sierra Club to the first data request of East Kentucky Power Cooperative, Inc. 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

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Fax 606-886-1455
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WES ADDINGTON
Mine Safety Project Attorney

August 8, 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: Case No. 2006-00472

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Director

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Mine Safety Project Attorney

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

RE: Case No. 2006-00472

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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

RESPONSES OF THE CUMBERLAND CHAPTER OF THE SIERRA CLUB
TO THE FIRST DATA REQUEST OF
EAST KENTUCKY POWER COOPERATIVE, INC.
DATED JULY 25, 2007

DATE SUBMITTED: AUGUST 8, 2007

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 1

RESPONSIBLE PERSON: Geoffrey M. Young

Request 1.

Reference Page 3 of your filed testimony. Please provide testimony you filed in the following Cases: 98-426, 98-474, 2000-459, Administrative Case 387 and the Testimony filed by KYDOE in Administrative Case 341.

Response 1.

The following document is a copy of the text of the testimony I drafted on behalf of the Kentucky Division of Energy that was submitted to the Commission in Administrative Case No. 341.

Unfortunately, I have been unable to find copies of my testimony in Cases No. 98-426, 98-474, 2000-459, and Administrative Case 387 in the Commission's file room.

Text of Testimony Presented by the

Kentucky Division of Energy

in Administrative Case No. 341

An Investigation Into the Feasibility of Implementing Demand-Side Management Cost Recovery and Incentive Mechanisms

On July 24, 1992, the Kentucky Public Service Commission (PSC) initiated an investigation into the feasibility of implementing demand-side management (DSM) cost recovery, revenue recovery and incentive mechanisms. The Division of Energy within the Kentucky Natural Resources and Environmental Protection Cabinet (NREPC/Energy) submitted comments, as did several other parties. On January 7, 1993, the PSC issued an order requesting additional comments and the clarification of certain issues raised by the parties. NREPC/Energy welcomes the opportunity to participate in the ongoing investigation of these issues.

1. The first question raised in the PSC's order of January 7, 1993 is: "Discuss whether the Commission presently has statutory authority to establish financial incentives to encourage a regulated utility's use of demand-side management."

NREPC/Energy is not in a position to put forth a legal opinion on whether the PSC has statutory authority in this area. However, we would like to offer comments that may logically address the question from the following perspective.

The important fact to recognize is that the present regulatory framework is not free of incentives. The present system of setting rates, as it has evolved over the past several decades, contains substantial economic incentives for electric utilities to expand sales of energy. As in many other states, the PSC in Kentucky periodically holds rate cases and sets electricity rates that are designed to allow the recovery of all prudent operating expenses and fixed costs, and to allow the utility an opportunity to earn an expected rate of return. In between rate cases, which is virtually all the time, a utility's revenue will increase if its sales increase.

Moreover, in states such as Kentucky, a fuel adjustment clause allows utilities to recover expenditures for fuel that are higher than expected. These additional costs are recoverable regardless of whether they arise because of higher unit fuel prices or increased quantities of fuel used to meet increased demand. If a utility's sales increase its revenues will increase, but any extra fuel costs it may incur are passed along via the fuel adjustment mechanism. A large fraction of the increase in revenue thus carries through to the utility company's bottom line as net income. Conversely, when total fuel costs are less than the projected amount, the utility must refund the difference to customers. If a DSM program reduces sales, the utility not only loses the revenue from the foregone sales, it must also make fuel adjustment payments to customers equivalent to the value of the fuel saved.

Under the present regulatory framework, the more effective a DSM program is in reducing electrical energy demand, the worse it is from the perspective of utility company profits.

David Moscovitz (1989) lists the following incentives inherent in the traditional framework of electric utility regulation:

"1) Each kWh a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings.

2) Each kWh saved or replaced with an energy efficiency measure, no matter how little it costs, reduces utility profits.

3) The only direct financial aspect of regulation that encourages utilities to pursue cost-effective conservation is the risk that dissatisfied regulators may disallow costs.

4) Purchases of power from cogeneration, renewable resources, or other non-utility sources add nothing to utility profits, no matter how cost-effective they are." (page 2)

These powerful existing incentives militate against the implementation of least-cost resource plans by utilities. The existing regulatory structure's strong economic bias toward increased sales leads utilities (other than cooperatives) to favor activities that boost sales and to shun DSM activities that would effectively reduce energy demand, even when the DSM measures are the least-cost ways of meeting customers' needs.

There is widespread consensus about the desirability of following the least-cost strategy. The regulation requiring jurisdictional electric utilities to submit integrated resource plans, 807 KAR 5:058, states:

> "This regulation prescribes rules for regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demands for electricity, <u>assure an adequate and reliable supply of electricity at the</u>

lowest possible cost for all electric utility customers within their service areas, and satisfy all related state and federal environmental and other laws and regulations." (emphasis added)

No party to Administrative Case No. 308 or to the present case (Administrative Case No. 341) has challenged the purpose or intent of least-cost planning. Even Kentucky Industrial Utility Customers (KIUC), who oppose policies specifically designed to encourage DSM, state: "The overriding concern of KIUC is that least cost planning principles be followed" (KIUC, October 1, 1992, page 3). However, by financially rewarding increased sales and financially punishing effective DSM programs, the existing regulatory framework embodies substantial economic incentives for utilities to depart from their least-cost plans.

NREPC/Energy believes that the PSC's first question can be looked at from a different perspective. Instead of focusing on whether the PSC has the statutory authority to establish incentives to encourage DSM, it might be fruitful to ask whether the PSC has the authority to remove the substantial financial disincentives to least-cost planning that are inherent in the traditional framework of regulations and decisions that has been established over the past several decades. Although NREPC/Energy has not offered a legal opinion, it would seem clear from the foregoing analysis that the PSC has the authority to remove the existing financial barriers to least-cost planning.

A question has been raised about the PSC's legal authority to establish incentives for DSM. However, during recent years our understanding of the potential impacts of cost-effective demand-side management has rapidly advanced to the point where it is clear that DSM will play a major role in the long-range least-cost plans of all electric utilities in the United States. NREPC believes that the PSC has a responsibility to facilitate the provision of an adequate and reliable supply of electricity at the lowest possible cost (i.e, to encourage the implementation of least-cost plans by utility companies in Kentucky). If there is any legal question to be raised, it should therefore be about the legality of maintaining the set of financial disincentives to least-cost planning inherent in the present, traditional regulatory framework.

2. "If the Commission presently lacks the statutory authority to establish financial incentives to encourage the use of DSM programs, identify and discuss the changes required to permit the Commission to establish such incentives."

Not applicable (see Question 1).

3. Electric Revenue Adjustment Mechanism (ERAM).

An ERAM does not maintain a utility's <u>earnings</u> at an approved level; rather, it maintains a utility's <u>revenue</u> at an approved level, and thereby compensates for changes in sales of electricity due to weather, economic conditions, DSM programs, and other factors. The ERAM implemented in California in 1978 is illustrative. At the time of a rate case, the California Public Utilities Commission establishes a utility's future non-fuel revenue requirements. The ERAM tracks non-fuel revenue as it is received from customers and compares it to the revenue limit established in the rate case. To the extent that actual non-fuel revenue collected by the utility deviates from the allowed revenue, the utility either surcharges or refunds customers (Moscovitz, 1989, page 40).

Because revenues are fixed, rather than earnings or profits, the company still has an incentive to cut costs and thereby increase its profits. In a report entitled "Ratemaking for Conservation: The California ERAM Experience," the authors compare ERAM to a regulatory framework that guarantees a utility's rate of return at an allowed level. The authors note that "ERAM can acutally be more favorable to the utilities than a rate-of-return guarantee because the cost minimizing incentive remains in place and the utility can, in fact, exceed its allowed rate of return on rate base by effective cost control" (Marnay & Comnes, 1990, page 5). The authors of a Michigan study address concerns that ERAM might reduce the discipline of market competition and make utilities complacent in their operations: "ERAM, however, retains an incentive for the utility to cut costs; in fact, cutting costs below the level authorized in the test year or ERAM proceeding is the principal way the utility can earn a return greater than its cost of capital" (Reid and Weaver, 1991, page 69).

The effect of cost-cutting measures on a utility's bottom line under ERAM is so dramatic, in fact, that the implementation of ERAM alone creates an incentive to reduce expenditures even on cost-effective DSM programs (Marnay & Comnes, page 35). It would therefore be desirable to combine a decoupling mechanism such as ERAM with one or more of the financial incentive mechanisms described in the PSC's order of July 24, 1992.

4. Formal PSC Review and Approval of Integrated Resource Plans.

a. NREPC/Energy believes that formal PSC review and approval of integrated resource plans (IRPs) would contribute to the implementation of effective least-cost plans by utility companies in Kentucky. By placing the IRPs submitted by all the utilities on a common basis, a formal approval process would tend to encourage the sharing of DSM-related information among utilities and standardization in the way information is presented. Utilities would also have more confidence that reasonable expenditures made pursuant to an approved IRP would not be disallowed later.

b. "State whether the Commission should review DSM expenditures as part of a formal review of a utility's IRP."

It is important to evaluate the actual results of DSM programs as well as expenditures. Considering both aspects will provide an indication of various DSM programs' cost-effectiveness, which is one of the criteria on which a regulatory scheme should be evaluated. The regulatory framework to be established by the PSC should meet several criteria, including the following:

1) The profits of a utility company should increase as it more closely approaches the implementation of the least-cost plan, and decrease as it deviates from the plan to a greater extent -- this should be the highest priority consideration;

2) Cost minimization should be encouraged, both in regard to demand-side and supply-side expenditures;

3) The regulatory framework should be relatively simple to administer;

4) The framework should be relatively fair and balanced, with some of the benefits resulting from least-cost planning accruing to customers as well as to utilities. (Moscovitz, 1989)

5. ERAM on a Per Customer Basis.

Three concerns raised by Joint Utilities about ERAM on a per customer basis are: a) high adminstrative costs caused by the perceived need for regular formal proceedings; b) the possible effect of changes in industrial demand on ERAM; and c) the counter-cyclical economic effect of ERAM on customers.

NREPC/Energy believes that these concerns are relatively minor, second- or third-order considerations when viewed in the context of the agreed-upon primary goal of regulatory reform: to ensure that the least-cost plan becomes the utility's most profitable plan.

a) In regard to administrative costs, the implementation of ERAM on a per customer basis would not necessarily require annual formal proceedings similar to a complete rate case. Although the California-style ERAM, which operates along with a future test year, requires annual proceedings, ERAM on a per customer basis can be used with either a future test year or historic test year approach (Moscovitz, 1989, page 41). Although adjustments would need to be made annually under ERAM on a per customer basis, annual proceedings at the level of a full-blown rate case would not be required. The annual ERAM proceedings would be limited to the review and approval of the cost adjustment factors (Reid and Weaver, 1991, page 66). The only data required for the calculation of adjustments under ERAM on a per customer basis -- revenues and number of customers by class -- are straightforward and verifiable. Because ERAM operates at the level of overall revenue, it does not require detailed calculations or estimations of efficiency (Moscovitz, 1989, page 40). In sum, NREPC/Energy believes that the overall gains in efficiency resulting from the decoupling of sales from profits far outweigh the additional administrative tasks which the implementation of ERAM on a per customer basis would require.

b) In their statement of October 1, 1992, Joint Utilities note that "some of the utilities in Kentucky have relatively large industrial loads on their systems. It is conceivable that changes in the industrial demands could have a significant effect on an ERAM on a per customer basis. The uncertainty of how the mechanism would deal with these types of changes raises a question of how equitably the mechanism will operate under the conditions in Kentucky." NREPC/Energy is not clear about the main thrust of these comments. Is the primary concern: 1) uncertainty about the way ERAM would operate; 2) equity effects within the industrial customer class; or 3) equity effects between the industrial and the other customer classes? In the absence of a numerical example or a more clear definition of the concern, it is difficult to gauge the potential magnitude of the effects to which Joint Utilities are referring. However, NREPC/Energy will attempt to address each of these three possible concerns below:

1) A public information effort aimed at explaining any newly introduced decoupling mechanism will probably alleviate uncertainty about the way the mechanism will operate in practice. 2) If the concern is that DSM measures adopted by one industrial firm may unduly shift financial burdens to other industrial customers, a reasonable solution would be for the utility to offer a range of industrial DSM programs. Opportunities for participation in cost-effective industrial energy conservation programs would then be maximized. 3) If the concern is about equity effects between industrial customers and other customers, it should be noted that ERAM on a per customer basis generates separate revenue-per-customer limits for each customer class. Adjustments made due to sales fluctuations in the industrial class should thus have no financial effect on the utility's non-industrial customers.

c) Joint Utilities correctly note that ERAM and ERAM on a per customer basis have a counter-cyclical economic effect, raising rates when the economy is weaker than expected and vice versa. Because electricity costs constitute a small fraction of the total costs of most customers, and because the percentage adjustments made due to ERAM are likely to be small, however, NREPC/ Energy believes that the counter-cyclical effect is not likely to be large. Assuming that the average customer's electric demand varies in proportion to changes in the overall economy, the impact of ERAM on a per customer basis would be to hold the average customer's electricity expenditures relatively constant regardless of fluctuations in the economy.

At the same time that ERAM dampens electricity cost fluctuations that are due to macroeconomic conditions, it also tends to reduce fluctuations due to unexpected extremes in weather. Under the present regulatory framework, very hot summer weather and very cold winter weather cause a customer's electricity bills to increase (and vice versa). Under ERAM or ERAM on a per customer basis, these fluctuations would be somewhat dampened, allowing customers to budget their electricity expenditures with more predictability. This reduction in weather-related uncertainty partially compensates consumers for the counter-cyclical effect of ERAM noted above.

In sum, NREPC/Energy believes that the concerns raised by Joint Utilities are not of sufficient gravity to cause the Commission to drop consideration of ERAM on a per customer basis. While there is no perfect regulatory framework, the decoupling of profits from sales is one of the major elements needed in order to enable least-cost planning to be implemented effectively in Kentucky. An ERAM-type system is one of the mechanisms that can achieve the necessary decoupling, and therefore should not be barred from further consideration by the second- or third-order concerns discussed above.

6. Weather Normalization Adjustment.

NREPC/Energy is unaware of any factors that would necessitate the use of a weather normalization adjustment in rate cases. As discussed above in the response to Question 5c, ERAM or ERAM on a per customer basis would tend to insulate utility company profits and customers' bills from unexpected fluctuations in the weather. Since the weather is not under utilities' control, there appears to be no reason to retain the present strong connection between weather fluctuations and company profits. A weather normalization adjustment in rate cases could reintroduce the connection that a decoupling mechanism such as ERAM or ERAM on a per customer basis had previously severed.

7. AG/Jefferson's Comments about Reconciled Fuel Adjustment Clause (FAC)

NREPC/Energy concurs with AG/Jefferson's comment that a reconciled FAC serves as a disincentive to conserve energy and reduce loads (see response to Question 1). Because changes in the FAC generally achieve only partial decoupling of profits from sales (Moscovitz, 1989, page 44), NREPC/Energy also concurs with AG/Jefferson's point that reform or elimination of the reconciled FAC should not be viewed as a substitute for the need for a decoupling or lost revenue recovery mechanism.

8. Participation of Natural Gas Distribution Utilities.

The key principle to be addressed by the present investigation into changes in the regulatory framework -- that a utility's least-cost plan should also be its most profitable plan -- applies to natural gas utilities as well as to electric utilities. Although the absence of centralized power plants in the capital structure of natural gas utilities makes their financial situation different than that of electric utilities, NREPC/Energy believes that consumers and providers of natural gas could also benefit from the removal of existing disincentives to least-cost planning, and should therefore be included in the present proceedings.

9. Natural Gas DSM Programs of Combination Utilities.

The regulatory framework established for gas and combination utilities should be evaluated using the same criteria as that established for electric utilities (see response to Question 4b). Although these criteria for evaluating the regulatory framework remain constant, the differences in financial structure between electric, combination, and natural gas utilities may lead the Commission to implement slightly different regulations related to DSM programs for each of the three types of utility.

10. "Describe how combination utilities should implement and measure DSM

programs that affect both electricity and natural gas consumption."

For DSM programs that affect both electricity and natural gas, a common unit of measurement is needed to allow planners to maximize overall program effectiveness. Two possible common units of measurement are: a) primary energy consumption; and b) total resource costs.

a) Measuring DSM programs according to their impact on primary energy consumption takes account of the efficiency losses arising from centralized power generation. By encouraging fuel switching in order to improve overall fuel cycle efficiency, the first measurement method would tend to minimize the generation of carbon dioxide for a given level of investment in DSM programs.

b) Measurement of DSM program effectiveness on the basis of minimizing total resource costs, however, more closely approximates the agreed-upon regulatory goal of encouraging least-cost planning: ensuring that a combined utility's least-cost plan is also its most profitable plan. For this reason, NREPC/Energy recommends that the Commission use total resource costs to measure the effectiveness of all DSM programs.

11. Joint Implementation of DSM Programs by Electric-only and Local Gas Companies.

If a regulatory framework is established that is basically fuel-neutral, there is no reason why electric and gas utilities could not cooperate in the implementation of DSM programs that save both electricity and natural gas.

12. Impact on Combination Utilities if DSM Revenue Recovery and Incentives Are Allowed for Electric DSM Programs Only.

If existing financial disincentives to least-cost planning are removed and incentives established only on the electricity side, many opportunities for electricity conservation that were previously judged "uneconomical" will become financially attractive. Some of these opportunities will involve fuel switching to natural gas. In the absence of a regulatory framework that applies equally to natural gas, somewhat more fuel switching is likely to occur than would be economically justified according to the criterion of minimizing total resource costs.

13. Beneficial Fuel Switching Programs.

Fuel switching programs that could achieve peak reduction, strategic conservation or valley filling and thereby benefit all energy providers and their customers include:

Fuel switching based on time-of-use factors, e.g, using gas to reduce a customer's annual peak electric load or vice versa;

Cogeneration installations, particularly those in which the heat is used at or near the generation site;

Any other fuel switching programs which minimize total resource costs and move the participating utilities in the direction of their least-cost plans.

14. Desirability of Using a Collaborative Process.

NREPC/Energy believes that the IRP process would be enriched by the input of a number of parties in addition to utility companies and the PSC. In other states, public utility commissions have facilitated or mandated a collaborative planning process in which various interested parties work together on a sustained basis to negotiate many of the technical issues associated with DSM programs. In New England, environmental groups such as the Conservation Law Foundation have, through participation in collaborative planning efforts, helped utility companies design several effective DSM programs (Cohen, 1990). The DSM programs developed through such processes tend to generate less controversy and litigation because many of the potential intervenors have been involved in the process of program development from the initial stages. In addition, information from a wide range of sources can be brought to bear on a commonly-defined problem. While the process may appear to be time-consuming in the short run, the improved quality of programs generated and the minimization of contentious litigation usually reduces the time required in the long run.

The authors of a report on shared savings mechanisms describe the ability of participants in collaborative processes to work through complex issues in a relatively short time:

> "Another example of the risk balancing achieved through consensus in the collaborative is the decision [in California] to base first-year program savings per participant... on estimates that are now assumed to remain unchanged for the lifetime of the measures installed in the first-year programs. In effect, this decision transfers all the risks of demand-side measure performance to the ratepayer. In return for immunity from the performance risk of their demand-side activities, however, the utilities agreed to initiate large-scale evaluations of their programs to measure those risks precisely.
>
> "The design of the shared savings incentives was the result of collaborative negotiations among stakeholders. While one can argue that the same results could have emerged from traditional regulatory forums, it is doubtful they could have emerged as quickly as they did in New England and California. In both cases, shared-savings incentives were established within one year after the initiation of discussions." (Eto, Destribats and Schultz, 1992, pp. 20-21)

15. Criteria for Selection of Members of a Collaborative Group or State-Level Panel.

NREPC/Energy believes that the major interests affected by utility regulation should be represented in a collaborative planning effort. These interests include utility companies, environmental groups, and industrial, commercial and residential customers. In addition, the inclusion of parties that have specific information or expertise concerning cost-effective DSM measures would enrich the process.

16. "State the reasons, if any, why a utility would not pursue cost-effective DSM programs when mechanisms are in place to ensure DSM program cost recovery, lost revenue recovery, or financial incentives."

Assuming that the regulatory changes described above actually realign a utility's financial incentives to correspond to its least-cost plan, then the only reason for utility inaction would be teh institutional inertia that sometimes exists in large organizations. Since the traditional regulatory framework has been in effect for so long, it may take some time for utility company personnel to adjust their ways of thinking to new economic realities. Internal shifting of staff from power marketing to DSM program planning and implementation may be required. The chief executive officer of the New England Electric Company, John Rowe, put it best when he relayed the internal company reaction: "You know, now that our load growth is dropping, my vice only reason for utility inaction would be the institutional inertia that sometimes exists in large organizations. Since the traditional regulatory framework has been in effect for so long, it may take some time for utility company personnel to adjust their ways of thinking to new economic realities. Internal shifting of staff from power marketing to DSM program planning and implementation may be required. The chief executive officer of the New England Electric Company, John Rowe, put it best when he relayed the internal company reaction: "You know, now that our load growth is dropping, my vice presidents are saying, can we stop this conservation crap now?" His answer to them was simple: "No, we can't. It's the single most profitable business we are in." (Cohen, 1990, page 45)

17. Cost-Effectiveness Tests.

The cost-effectiveness test that the PSC and utility companies should use to evaluate the cost-effectiveness of both demand-side and supply-side programs is the societal test, which consists of the total resource cost test plus an adjustment to account for external costs to society such as the emission of environmental pollutants. The total resource cost test accounts for all economic costs and benefits accruing to utilities, program participants and non-participants. The adjustment for external costs ensures that the energy sector will not lower its costs by unduly shifting environmental costs to society as a whole.

To use other cost-effectiveness tests such as the ratepayer impact measure (RIM), also known as the no-losers test, introduces distortions to welfare maximization as described in the economic theory of free markets. In neoclassical economic theory, welfare is maximized if society chooses at all times to invest in the option of lowest marginal cost, i.e. the least-cost plan. By requiring DSM programs to meet the more restrictive no-losers test arising out of distributional concerns, the RIM establishes different evaluation criteria for demand-side programs than for supply-side programs, which always affect non-participants. The RIM thus leads to less investment in DSM than would be economically most efficient under least-cost and free market principles (NARUC, 1988, page IV-5).

As NREPC/Energy noted in our response to the PSC order of July 24, 1992, there are several strategies that can serve to minimize the distributional impacts of implementing a least-cost plan. These include:

a) Offering a wide range of DSM programs which allow most or all customers to participate if they choose;

b) Minimizing program delivery costs by encouraging customers to pay part of the initial cost of DSM measures [although this may have the side effect of reducing customer participation in the program];

c) Constructing a low-impact DSM plan by mixing programs with positive and negative rate impacts;

d) Offering efficiency improvements to industrial customers instead of promotional or individual negotiated rates.

18. Customer Participation in DSM Programs.

NREPC/Energy believes that customer participation in DSM programs should be voluntary. Indeed, for many such programs, there is no practical way to require customers to install energy conserving technologies or to keep them in operation once installed.

If participation is voluntary, DSM program costs should be recovered from all ratepayers, not only program participants. To allocate DSM program costs only to participants is to impose a stringent form of the ratepayer impact measure (RIM), which is inappropriate for the reasons discussed in the response to Question 17. Presently, supply-side investments are recovered from all ratepayers, not just those whose demand is met by the particular supply-side resource under consideration. To restrict the cost recovery of demand-side investments to participants only would lead to the elimination of numerous cost-effective DSM measures and would cause utilities to overinvest in supply-side resources and depart from their least-cost plans.

REFERENCES

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Eto, J., Destribats, A., and Schultz, D. (1992), "Sharing the Savings to Promote Energy Efficiency," Lawrence Berkeley Laboratory.

Marnay, C. and Comnes, G.A. (1990), "Ratemaking for Conservation: The California ERAM Experience," Lawrence Berkeley Laboratory.

Moscovitz, D. (1989), "Profits and Progress Through Least-Cost Planning," for the National Association of Regulatory Utility Commissioners (NARUC).

National Association of Regulatory Utility Commissioners (NARUC) (1988), *Least-Cost Utility Planning Handbook for Public Utility Commissioners, Volume 2, The Demand Side: Conceptual and Methodological Issues*, Washington, DC.

Reid, M. and Weaver, E. (1991), "Michigan Regulatory Incentives Study for Electric Utilities," for NARUC.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 2

RESPONSIBLE PERSON: Geoffrey M. Young

Request 2.

Beginning on page 5, line 10 of your testimony, you refer several times to "energy waste." On page 5, line 13, you refer to "energy inefficiency." Please define these two terms. Please explain whether they are the same or different from one another.

Response 2.

I consider these two terms to be equivalent. In the important book, *Natural Capitalism: Creating the Next Industrial Revolution*, the authors, Paul Hawken, Amory Lovins, and L. Hunter Lovins cite the definition of waste developed by Taiichi Ohno: "any human activity which absorbs resources but creates no value." Because their discussion of the concept of waste is so instructive, illuminating and helpful, I have attached a copy of pages 125-131 of their book below. [Natural Capitalism, 1999, Little, Brown and Co., Boston, New York, London] opportunities for social contact, beautify the neighborhood, and make it safer for children." Corbett was solving for pattern as Christopher Alexander teaches in his famous design text, *A Pattern Language*:[17] "When you build a thing, you cannot merely build that thing in isolation, but must also repair the world around it, and within it, so that the large world at that one place becomes more coherent, and more whole; and the thing which you make takes its place in the web of nature, as you make it."

CHAPTER 7

Muda, Service, and Flow

Mental muda *spectacles — A continuous flow of value — Eddies and undertows of waste — Simple now and always — Allowing value to flow — Making money the same way — Leasing carpets, color, and chemicals — Ending the business cycle*

PERHAPS "THE MOST FEROCIOUS FOE OF WASTE HUMAN HISTORY HAS PRODUCED"[1] was Taiichi Ohno (1912–90). Ohno-sensei was the father of the Toyota Production System, which is the conceptual foundation of the world's premier manufacturing organization, and one of the pivotal innovators in industrial history. His approach, though adopted successfully by Toyota, remains rare in Japan. However, it has shown remarkable results in America and elsewhere in the West, and is poised for rapid expansion now that it has been systematized by industrial experts Dr. James Womack and Professor Daniel Jones. With their kind permission, we gratefully quote and paraphrase their book, *Lean Thinking*, in the hope that more business leaders will read it in full.[2]

Ohno created an intellectual and cultural framework for eliminating waste — which he defined as "any human activity which absorbs resources but creates no value." He opposed every form of waste.[3] Womack and Jones restated thus his classification of the forms of waste: "mistakes which require rectification, production of items no one wants so that inventories and remaindered goods pile up, processing steps which aren't actually needed, movement of employees and transport of goods from one place to another without any purpose, groups of people in a downstream activity standing around waiting because an upstream activity has not delivered on time, and goods and services which don't meet the needs of the customer." Ohno called these *muda*, which is Japanese for "waste," "futility," or "purposelessness." Each of these classes of *muda* involves a whole family of blunders, which range from activities like having to inspect a product to see if it has the quality it should have had in the first place (an unneeded process step) to filling a new-car lot with vehicles that meet no specific demand — if the cars

EKPC Request 2
Page 2 of 5

were wanted, customers would have bought them already — and then discounting them enough to sell them. Ohno's and his students' vast practical experience helped them to develop penetrating modes of perception — mental "*muda* spectacles" — that reveal the previously invisible waste all around us.

So where is all this *muda?* Start, say, by visiting a job site where builders are constructing a custom house. You'll notice periods of recurrent inactivity. But these lags aren't taking place because the workers are lazy. Builder Doyle Wilson discovered that five-sixths of the typical custom-house construction schedule is spent in *waiting* for specialized activities to be completed and fitted into a complex schedule, or in *reworking* — tearing out and redoing work that was technically wrong or that failed to meet the customer's needs and expectations. Eliminating even part of that wasted time can create a huge competitive advantage for a savvy construction firm.

Or take a much more familiar experience: air travel. Often you can't get a direct flight to where you want to go. Instead, you must somehow get to a major airport, fly in a large airplane to a transfer point quite different from your actual destination, become "self-sorting cargo" in a huge terminal complex once you arrive there, and board another large plane going to the destination you originally wanted. Most travelers tolerate this because they are told that it's a highly efficient system that fully utilizes expensive airplanes and airports. Wrong. It looks efficient only for the tautological reason that the airplanes are sized for those large hubs, which are designed less for efficiency than to monopolize gates and air-traffic slots, thus *reducing* competition and economic efficiency as well as convenience.

Much if not most air travel would cost less, use less fuel, produce less total noise, and be about twice as fast point-to-point by using much smaller and more numerous planes that go directly from a departure city to a destination. That concept, reinforced by turning around planes in fifteen instead of thirty minutes, is the secret of Southwest Airlines' profits. In contrast, most other airlines have established systems designed to transfer idleness from capital to customers. These systems are so riddled with waste that Jones once found nearly half the door-to-door time of a typical intra-European air trip to have been spent in waiting in ten different lines, seven baggage-handling operations, eight inspections asking the same questions, and twenty-three processing steps performed by nineteen organizations. Each was specialized to

perform its own narrowly defined task "efficiently" — in a way that ultimately added up to dreadful inefficiency for the customer. Removing inefficiencies like these through whole-system engineering of the firm is the next great frontier of business redesign.

The nearly universal antidote to such wasteful practices is what Womack and Jones call "lean thinking," a method that has four interlinked elements: the *continuous flow* of value, as *defined* by the customer, at the *pull* of the customer, in search of *perfection* (which is in the end the elimination of *muda*). All four elements are essential to lean thinking: For example, "if an organization adopts lean techniques but only to make unwanted goods flow faster, *muda* is still the result."[4] The parts of the definition also functionally reinforce one another. "Getting value to flow faster always exposes hidden *muda* in the value stream. And the harder you pull, the more the impediments to flow are revealed so they can be removed. Dedicated product teams in direct dialogue with customers always find ways to specify value more accurately[,] and often learn of ways to enhance flow and pull as well."

Value that flows continuously at the pull of the customer — that is, nothing is produced upstream until someone downstream requests it — is the opposite of "batch-and-queue" thinking, which mass-produces large inventories in advance based on forecast demand. Yet so ingrained is batch-and-queue — and so deeply embedded is the habit of organizing by functional departments with specialized tasks — that Womack and Jones caution: "[P]lease be warned that [lean thinking] requires a complete rearrangement of your mental furniture." Their basic conclusion, from scores of practical case studies, is that specialized, large-scale, high-speed, highly efficient production departments and equipment are the key to *in*efficiency and *un*competitiveness, and that maximizing the utilization of productive capacity, the pride of MBAs, is nearly always a mistake.[5]

Consider the typical production of glass windshields for cars. Economies-of-scale thinking says that the giant float-glass furnace should be as large as possible: a theoretically ideal situation would be if all the flat glass in the world could be made in a single plant. Big flat sheets of glass emerge from the furnace and are cut into pieces somewhat larger than a windshield. The glass is cooled, packed, crated, and shipped 500 miles to the fabricator. There, 47 days later, it's unpacked and cut to shape, losing 25 percent in the process. It is then reheated and drooped or pressed into the right curving shape. (Because each car model has different specifications, huge batches of windshields are shaped at once while a given set of dies is installed.) Then the glass is cooled, repackaged, and shipped 430 miles to the glass encapsulator. There, 41 days later, it's unpacked, fitted with the right edge seals and other refinements, repacked, and shipped another 560 miles to the car factory. There, 12 days later, it's unpacked and installed in the car. Over 100 days have elapsed and the glass has traveled nearly 1,500 miles, almost none of which contributes to customer value.

Each part of this sequence may look efficient to its proprietor, but in fact the cooling, reheating, unpacking, repacking, shipping, and associated breakage is all *muda*. An efficient system for manufacturing windshields would build a small plant at the same place as the car factory, and carry out all the steps in the production process in immediate succession under one roof, even though several machines and companies might be involved. The machinery would be sized to deliver windshields only as fast as the automotive assembly line "pulls" them in.

Traditional substitutions of complex machines for people can backfire, as Pratt & Whitney discovered. The world's largest maker of jet engines for aircraft had paid $80 million for a "monument" — state-of-the-art German robotic grinders to make turbine blades. The grinders were wonderfully fast, but their complex computer controls required about as many technicians as the old manual production system had required machinists. Moreover, the fast grinders required supporting processes that were costly and polluting. Since the fast grinders were meant to produce big, uniform batches of product, but Pratt & Whitney needed agile production of small, diverse batches, the twelve fancy grinders were replaced with eight simple ones costing one-fourth as much. Grinding time increased from 3 to 75 minutes, but the throughput time for the entire process *decreased* from 10 days to 75 minutes because the nasty supporting processes were eliminated. Viewed from the whole-system perspective of the complete production process, not just the grinding step, the big machines had been so fast that they slowed down the process too much, and so automated that they required too many workers. The revised production system, using a high-wage traditional workforce and simple machines, produced $1 billion of annual value in a single room easily surveyable from a doorway. It cost half as much, worked 100 times faster, cut changeover time from 8 hours to 100 seconds, and would have repaid its conversion costs in a year even if the sophisticated grinders were simply scrapped.

Just as unwanted weight in a car or unwanted heat in a building is prone to compound and multiply, *muda* tends to amplify itself, because excessive scale or speed at any stage of production turns the smooth flow of materials into turbulent eddies and undertows that suck down earnings and submerge whole industries. Remember chapter 3's saga of the aluminum cola can? It takes 319 days in production to get to the customer's hand, then minutes to reach the trash bin. This is 99 and 96/100ths percent pure *muda*. For such a massive batch-and-queue system to produce what the customer perceives as an uninterrupted supply of cola requires huge inventories at every upstream stage to deal with unforeseen fluctuations in demand or delays in supply. Wherever there's a bottleneck, the supplier adds buffer stocks to try to overcome it — thereby counterintuitively making the stop-and-go traffic of the materials flow even worse.

All this results from the mismatch between a very small-scale operation — drinking a can of cola — and a very large-scale one, producing it. The production process is designed to run in enormous batches, at very high speeds, with very high changeover costs. But that logic is the result of applying to business organization precisely the same design flaw — discussed in the previous chapter at the level of components — namely, optimizing one element in isolation from others and thereby pessimizing the entire system. Buying the world's fastest canning machine to achieve the world's lowest fill cost per can presumably looks like an efficient strategy to the canner. But it doesn't create customer value at least cost, because of such expenses as indirect labor (in such forms as technical support), the inventories throughout the value chain, and the pervasive costs and losses of handling, transport, and storage between all the elephantine parts of the production process. Just as Pratt & Whitney's grinders looked fast and cheap per grind but were slow and costly per finished blade, from a whole-system perspective, the giant cola-canning machine may well cost *more* per delivered can than a small, slow, unsophisticated machine that produces the cans of cola locally and immediately on receiving an order from the retailer.

The essence of the lean approach is that in almost all modern manufacturing, the combined and often synergistic benefits of the lower capital investment, greater flexibility, often higher reliability, lower inventory cost, and lower shipping cost of much smaller and more localized production equipment will far outweigh any modest decreases in its narrowly defined "efficiency" per process step. It's more efficient overall, in resources and time and money, to scale production properly, using flexible machines that can quickly shift between products. By doing so, all the different processing steps can be carried out immediately adjacent to one another with the product kept in continuous flow. The goal is to have no stops, no delays, no backflows, no inventories, no expediting, no bottlenecks, no buffer stocks, and no *muda*. Surprisingly, this is as true for small- as for large-scale production.

SIMPLIFICATION AND SCALE

One of the keys to lean thinking is simplification. In the previous chapter, simplification was a design opportunity for components and products. Enlarged to the context of the whole process or plant, it gains the wider ability to save simultaneously such resources as space, materials, energy, transportation, and time.

The VW Golf's mirrors have four completely different designs, each containing 18–19 elaborately engineered parts, and each available in 17 colors. The exterior rearview mirrors designed by Nissan for British-assembled Micra cars have one design, with four parts, and come in four colors. As a result, Nissan's production system involves only four mirror specifications while VW deals with sixty-eight, each with more than four times as many parts.[6] While it's not obvious that VW is providing premium value in offering customers more choices — choices they neither necessarily want nor are willing to take the trouble to decide about — it *is* obvious that multiplying product variety times product complexity bears heavy costs.

Another key question is: What's the right size for the task? As the case studies earlier in this chapter illustrate, matching the scale of production equipment to the rate of pull by the next step downstream is another key theme of lean thinking. *Every* tool, machine, or process should be the right size for the job. Too big is at least as bad as too small — and it is often worse, because it allows for less flexibility and creates many indirect forms of *muda*. However, right-sizing doesn't mean making everything small. E. F. Schumacher, whose classic *Small Is Beautiful* (1973) first questioned the cult of gigantism in business, emphasized that it would be just as pointless to run an aluminum smelter with little wind machines as it would be to heat houses with a fast breeder reactor; they're both a mismatch of scale. Moreover, both Schumacher and lean thinking teach that right-sizing is a *system* attribute.[7]

The right size for a soda-canning machine or a blade-grinding machine or a windshield-making machine depends on the entire production process viewed in the context of a whole market structure and business logic. Again, optimizing a machine's size in isolation pessimizes the system of which it is a part: The right size *depends on the rate and location of customer pull.*

History has strongly confirmed this conclusion with regard to electric power systems, the most capital-intensive sector of the economy. The proper size for a power station can't be determined in isolation from the system that supplies its fuel, delivers its electricity to customers, and creates its competitive business context. The U.S. utility industry, and most of its counterparts abroad, will take decades to recover from the financial consequences of doctrinaire gigantism. From that chastening experience, a compelling literature on the economics of power-plant scale emerged during the 1970s and early 1980s, then reemerged in the 1990s. By combining the rigorous analytic tools of portfolio theory, electrical engineering, and other disciplines, a recent synthesis found[8] that approximately seventy-five uncounted effects of scale on economics typically make decentralized power sources about tenfold more valuable than traditionally supposed. That is enough to make even solar cells cost-effective, *now*, in most applications.

While many details differ, the same whole-system design imperative applies, and analogous critiques are starting to emerge, in water and wastewater systems. The whole system that comprises classical central sewage-treatment plants and their farflung collection sewers — each piece optimized in isolation — is far costlier than such local or even on-site solutions as biological treatment. That is the case because even if the smaller plants cost more per unit of capacity (which they generally don't), they'd need far less investment in pipes and pumps — often 90 percent of system investment — to collect sewage from a greater area to serve the larger plant. They'd also recover valuable nutrients and water more thoroughly, with better quality, and closer to where they're needed, saving more distribution costs.

Comparable whole-system scale economics should apply to most technical systems, including transportation, communications, and even manufacturing — whose flow of materials between different production steps is somewhat analogous to the flow of power, water, or wastewater. The exploration of such applications has barely begun. Yet the conceptual lessons of the power-system synthesis have revealed

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 3

RESPONSIBLE PERSON: Geoffrey M. Young

Request 3.

Reference Page 8, Lines 7 and 9 of your testimony. Please provide copies of studies and other evidence that support the assertion: "The more electricity EKPC sells, the more money it makes."

Response 3.

The following analysis makes use of an estimate of the percentage of EKPC's total costs that are variable and the percentage that are fixed. The attached worksheet indicates that approximately 55% of EKPC's costs are variable (i.e., fuel and purchased power) and approximately 45% fixed. It indicates also that EKPC's average revenue per kWh is approximately 7 cents. Applying these percentages implies that on average, each kWh that EKPC sells provides approximately 3.9 cents of revenue intended to cover the average fuel costs and 3.1 cents to cover EKPC's fixed costs.

Following the methodology provided by David Moskovitz in his 1989 report, *Profits and Progress through Least-Cost Planning*, one can project the financial impacts of incremental energy sales on EKPC's revenue and net revenue under a range of assumptions about the short-term cost of fuel. I will consider three scenarios.

a) EKPC increases its sales of electricity by 1 kWh during average conditions. In this case, its incremental cost of fuel was 3.9 cents and its incremental revenue was 7.0 cents. EKPC's net revenue increased by 3.1 cents.

b) EKPC increases its sales of electricity by 1 kWh during high-cost conditions. Assuming the short-term fuel cost is 10.0 cents/kWh during a time period when load is relatively high. EKPC will receive incremental revenue of 7.0 cents and pay a fuel cost of 10.0 cents; the short-term effect on net revenue will be a negative 3.0 cents. The fuel adjustment clause (FAC), however, will soon compensate EKPC for the difference between its short-term fuel cost and its average fuel cost. The operation of the FAC will allow EKPC to recover the difference between 10.0 cents and 3.9 cents, i.e., 6.1 cents, by raising rates in a subsequent period. The final impact resulting from the sale of this incremental kWh will be 6.1 cents – 3.0 cents = 3.1 cents.

c) Conversely, if EKPC increases its sales of electricity by 1 kWh during low-cost (off-peak) conditions, the FAC will require EKPC to refund money to its customers. If EKPC's fuel cost during an off-peak period is 2.0 cents/kWh, it will earn 5.0 cents in net revenue in the short term. However, the FAC will soon require EKPC to refund the difference between its average fuel cost of 3.9 cents and its short-term fuel cost of 2.0 cents, yielding a refund of 1.9 cents. The final impact resulting from the sale of this incremental kWh will be 5.0 cents – 1.9 cents = 3.1 cents.

[Source: Moskovitz, pages 4-5. The entire report is reproduced in response to the PSC Staff's first information request 1a.]

EKPC Fixed vs Variable costs - 2005

Fixed	Var (in thousands)
103,632	263,434 - fuel
21,029	109,571 - purchased power
52,038	373,005
38,642	
69,844	
(5,898)	
(6,226)	
32,555	
(742)	
(575)	
304,299	

304,299 + 373,005 = 677,304

Fixed = 304,299 / 677,304 = 44.9 %

Variable = 373,005 / 677,304 = 55.1 %

Derived from

EKPC Consolidated statements of revenue and expenses,

Application, Exhibit M. page 3

EKPC's average revenue per kWh =

$807,088,887 / 11,551,046 MWh = $.0699 / kWh

(Source: EKPC data to Utility Working Group; See response to PSC staff's 1st Data Request 2, page 30 of 31.)

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 4

RESPONSIBLE PERSON: Geoffrey M. Young

Request 4.

On page 14, lines 8-9, you say that in Kentucky, "Those DSM programs designed to shift peak loads to non-peak periods have tended to be somewhat larger and more effective." To which DSM programs are you referring? Please identify and provide copies of the studies or other evidence that show that these programs are "more effective."

Response 4.

I had in mind specifically E.ON's direct load control program for residential and commercial customers. On July 19, 2007, E.ON filed an application with the Commission to continue and expand its DSM programs. [Case No. 2007-00319] The attached pages copied from Volume 1 of that application describe the scope and effectiveness of E.ON's Residential and Commercial Load Management Program. Between 2001 and June 2007, E.ON has installed radio-controlled switches on over 114,000 air conditioners, water heaters, and swimming pool pumps.

With a 2008 budget of $10.0 million, the "Residential Demand Conservation" Program is E.ON's largest single DSM program. It represents 39% of E.ON's total annual investment in DSM. [E.ON Application, Vol.1, page 10] It is also currently Kentucky's largest single DSM program.

An indication of the effectiveness of the residential and commercial load control programs is given by E.ON's statement that "On August 2, 2006, LG&E and KU set a new combined system peak of 6,852 MW. During this peak, load control devices were activated and over 93 MW of demand was eliminated from the peak." [Ibid., page 20]

Another indication of the programs' effectiveness is provided by E.ON's estimate that the benefit/cost ratio (according to the total resource cost test) of the Residential Load Management Program is 3.75 and that of the Commercial Load Management Program is 6.75. These are the two highest-rated TRC results of all of E.ON's DSM programs. [Ibid., page 8]

E.ON
Case No. 2007-00319 Filed 7/19/07

ES.4 Demand-Side Management Cost Recovery Mechanism (DSMRM)

The attached tariffs contain separate cost recovery mechanisms for LG&E and KU. The proposed Energy Efficiency programs will be operated as one group of programs available to customers of LG&E and KU. While the programs will operate as "one" from the customer's perspective, separate accounting will allow for the proper recovery of the DSMRM components from each utility's individual customers within the appropriate rate classes. The attached tariffs assume an effective date of January 1, 2008.

The Demand-Side Management Balance Adjustment ("DBA") is used to reconcile the difference between what was actually billed and what should have been billed for approved Energy Efficiency programs. DBA adjustments will become effective each April for the purpose of reconciling DBA revenues collected in the previous calendar year.

ES.5 Program Evaluation

Program evaluation is necessary to control quality of the programs, to optimize resources and to respond to customers' needs. Program evaluation is usually done in the following two phases: 1) process evaluation and 2) impact evaluation. Process evaluation is a systematic assessment of a utility Energy Efficiency program for the purposes of improving its design, its delivery, and the usefulness and quality of the services delivered to the customers, while impact evaluation focuses on quantifying the energy and demand savings and other economic benefits of the program. All programs will be evaluated by the Companies to determine their benefits and costs. The Companies will continue to monitor all the programs and if any program is deemed to be ineffective, the Companies reserve the right to cancel or discontinue the program with a letter or motion to the Commission.

ES.6 Program Benefit / Cost Calculations

Listed below are the benefit / cost ratios performed according to the California Standard Practice Manual for each of the proposed Energy Efficiency programs. The Companies worked closely with program design consultants to create programs that are in the best interest of the participating customers and result in programs passing the Total Resource Cost Test. Each of the proposed programs passes the Participant Test (Programs designated n/a have no participant costs) and the Total Resource Cost Test.

The benefit / cost calculations were performed using DSManager. DSManager is a PC-based software package developed by EPS Solutions under contract with Electric Power Research Institute ("EPRI"). The DSManager output reports for each of the programs can be found in Volume II Appendix B. The DSManager input summary report for each of the programs can be found in Volume II Appendix C.

Benefit/Cost Ratios

	Participants Test	Utility Cost Test	Ratepayer Impact Test	Total Resource Cost Test
Residential Conservation	4.19	1.37	0.60	1.50
Residential Load Management	Infinity	2.67	1.90	3.75
Commercial Load Management	Infinity	4.52	2.09	6.12
Res. Low Income Weatherization	Infinity	0.81	0.37	2.28
Commercial Conservation /Rebates	4.30	11.21	0.89	3.64
Residential High Efficiency Lighting	11.04	4.40	0.64	2.87
Residential New Construction	2.23	1.49	0.61	1.09
Residential HVAC Tune Up	7.66	1.13	0.62	1.10
Commercial HVAC Tune Up	20.32	2.04	0.53	1.79
*Customer Education & Public Information	n/a	0	0	0
*Dealer Referral Network	n/a	0	0	0
*Program Development and Admin.	n/a	0	0	0
Overall Portfolio	**7.02**	**3.31**	**0.89**	**2.80**

* Benefits are captured in analysis of supported programs

ES.7 Timeline

Implementation of this program plan will require employment of additional personnel by the Companies. While going through the approval process of this program plan, the Companies will not add Energy Efficiency Operations employees but do intend to move forward with the process of selecting contractors for the programs. The Companies will not sign contracts with the successful bidders until the program plan and corresponding cost recovery have been approved by the Commission. Implementation plans will proceed under the assumption that approval will be granted prior to January 1, 2008. The Companies intend to implement all programs as quickly as reasonably possible following approval with reimplementation of existing programs taking priority. Assuming no major delays in finding qualified employees, all programs are expected to be operational by the end of 3rd quarter 2008.

E.S.9.2 Annual Budget – Programs & Rate Class

	2008	2009	2010	2011	2012	2013	2014
Residential Programs							
Residential Conservation	642,432	698,339	741,895	770,249	777,624	796,276	815,473
Residential Demand Conservation	9,991,125	10,247,157	10,793,803	9,782,181	10,241,082	9,091,041	8,661,803
WeCare	1,728,665	1,738,166	1,788,208	1,868,463	1,892,711	1,947,260	2,003,401
Responsive Pricing Pilot	1,094,220	221,810	221,810	107,500	0	0	0
Residential High Efficiency Lighting	3,434,829	3,388,963	3,396,569	3,416,046	3,447,148	3,489,677	3,543,481
Residential New Construction	859,994	864,292	1,064,054	1,102,635	1,204,469	1,281,140	1,401,685
Residential HVAC Diagnostics & Tune Up	204,825	339,747	392,391	487,332	482,994	492,092	537,642
Customer Education & Public Information	2,480,594	2,531,811	2,606,787	2,703,261	2,825,110	2,978,045	3,170,248
Dealer Referral Network	129,058	118,886	121,750	124,686	127,695	130,781	133,943
Program Development & Administration	603,782	622,110	637,899	654,104	670,737	687,808	705,331
Total Residential Programs	**21,169,525**	**20,771,282**	**21,765,166**	**21,016,458**	**21,669,571**	**20,894,119**	**20,973,008**
Commercial Programs							
Commercial Demand Conservation	436,110	398,688	450,564	438,750	431,397	447,948	432,350
Comm. Conservation w/Prescriptive Rebates	3,177,328	3,149,081	3,170,021	3,214,230	3,213,256	3,235,571	3,258,365
Responsive Pricing Pilot	178,129	38,465	38,465	17,500	0	0	0
Commercial HVAC Diagnostics & Tune Up	190,077	268,122	328,117	411,778	455,180	466,894	512,048
Customer Education & Public Information	544,521	555,763	572,222	593,399	620,146	653,717	695,908
Dealer Referral Network	28,330	26,097	26,726	27,370	28,031	28,708	29,402
Program Development & Administration	132,538	136,561	140,027	143,584	147,235	150,982	154,829
Total Commercial Programs	**4,687,033**	**4,572,777**	**4,726,141**	**4,846,611**	**4,895,245**	**4,983,821**	**5,082,902**
Total Plan	**25,856,558**	**25,344,059**	**26,491,306**	**25,863,068**	**26,564,816**	**25,877,939**	**26,055,910**

Case No. 2007-00319 Filed 7/19/07

LG&E and KU
2008-2014 ENERGY EFFICIENCY PROGRAM PLAN

Program Name: Residential and Commercial Load Management

2.1 Program Description

The objective of this program is to reduce peak demand and energy usage through the installation of load control devices on residential and commercial customer equipment, emphasizing central air conditioners and heat pumps, but also including electric water heaters and pool pumps.

Load reduction is accomplished by cycling equipment on and off according to a predetermined control strategy. For example, if an air conditioner is turned off for 15 minutes during a 30-minute period, it is "cycled" on a 50 percent control strategy. The Company's strategy has been to control between 30% and 45%, depending on temperature and customer equipment, resulting in an average demand reduction of over 1 KW per switch.

Additional energy savings come from the use of the setback features of a programmable thermostat, which includes similar technology as the switch to cycle the unit during peak periods. The U.S. Department of Energy ("DOE") indicates that proper use of a programmable thermostat can result in savings of around 10% a year on heating and cooling usage by simply turning the thermostat back *10°–15° for eight hours per day*, when asleep or away.

2.1.1 Program History

In 2001, the Companies began implementation of this load control program ("Demand Conservation") and as of June 1, 2007 over 98,000 devices have been installed on air conditioners, electric water heaters, and pool pumps. Because these devices often control multiple appliances, there are over 114,000 air conditioners, water heaters and pool pumps under control.

The current electric system summer peak demand reduction is in excess of 107 MW. Program performance and demand reduction assumptions have been verified by independent program evaluations by SBC in 2004 (see Volume III Appendix E) and GoodCents Solutions in 2005 (see Volume III Appendix F).

The program plans call for up to 20 control days per year. As seen in the table below, the Companies have historically utilized the system an average of 11 days per year.

Year	Number of control days
2003	11
2004	7
2005	16
2006	10

On August 2, 2006, LG&E and KU set a new combined system peak of 6,852 MW. During this peak, load control devices were activated and over 93 MW of demand was eliminated from the peak.

During 2005, equipment manufacturers began incorporating the functions of a load control switch into programmable thermostats. During the winter of 2005-2006, the Companies purchased 2,000 load control thermostats and began deploying them to customers. The functionality of the thermostat is the same from a load control perspective, but has the added benefit of additional energy savings through the use of programmable temperature set back at night or during times the home is not occupied.

Currently, customers are offered the option of a load control "switch" with a bill credit during the summer months or a load control programmable thermostat without the bill credit. While the first cost of the programmable thermostat option has a higher first cost, the elimination of the on-going bill credits results in lower life cycle cost. The thermostat option also results in significant Kwh energy savings and reduced HVAC contractor concerns regarding installation of load control switches and their perceived interference with system operation.

2.2 Rationale for Program

Load management of air conditioning, and other large loads, has become a significant tool to delay future generating capacity since it targets one of the main drivers of the summer peak. Current market saturation is approximately 15% of residential central air conditioning units. Based on results seen in other utilities such as Excel Energy and Florida Power & Light, it is not unreasonable for the Companies to double this market penetration. This program should help in delaying the need for future generation capacity. This program has also provided another tool by responding to emergency situations. At the time of forced outages, the immediate shed of all controlled loads, for short periods, has given the Companies a new tool to respond in the most cost effective manner. This short-term load reduction helps the Companies by providing additional time to maintain or return to operational compliance required by the North American Reliability Council ("NERC").

2.3 Participation Goals

A saturation of approximately 33% would be required to obtain the program's goal of 199,000 air conditioning participants. The Companies assumed that participation in the air conditioning portion of this program would be split equally among LG&E and KU customers. We propose to install load control devices according to the table below:

2.3.1

Residential participation goals

	Thermostats A/C		Switches A/C		Total A/C		Water Heaters		Total Devices	
	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.
2008	11,700	11,700	6,300	6,300	18,000	18,000	6,300	6,300	24,300	24,300
2009	11,700	23,400	6,300	12,600	18,000	36,000	6,300	12,600	24,300	48,600
2010	11,700	35,100	6,300	18,900	18,000	54,000	6,300	18,900	24,300	72,900
2011	9,100	44,200	4,900	23,800	14,000	68,000	4,900	23,800	18,900	91,800
2012	9,100	53,300	4,900	28,700	14,000	82,000	4,900	28,700	18,900	110,700
2013	6,500	59,800	3,500	32,200	10,000	92,000	3,500	32,200	13,500	124,200
2014	5,200	65,000	2,800	35,000	8,000	100,000	2,800	35,000	10,800	135,000

Commercial participation goals

	Thermostats A/C		Switches A/C		Total A/C		Water Heaters		Total Devices	
	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.	Annual	Cumul.
2008	520	520	280	280	800	800	-	-	800	800
2009	520	1,040	280	560	800	1,600	-	-	800	1,600
2010	520	1,560	280	840	800	2,400	-	-	800	2,400
2011	520	2,080	280	1,120	800	3,200	-	-	800	3,200
2012	455	2,535	245	1,365	700	3,900	-	-	700	3,900
2013	390	2,925	210	1,575	600	4,500	-	-	600	4,500
2014	325	3,250	175	1,750	500	5,000	-	-	500	5,000

2.3.2 Energy Impacts - Residential

	2008	2009	2010	2011	2012	2013	2014
MWh	4,802	9,605	14,407	18,142	21,877	24,545	26,679
MW	20	39.9	59.9	75.4	90.9	102	110.9
CCF	284,000	576,000	851,000	1,071,000	1,292,000	1,449,000	1,575,000

2.3.3 Energy Impacts - Commercial

	2008	2009	2010	2011	2012	2013	2014
MWh	213	427	640	854	1,040	1,201	1,334
MW	1.2	2.3	3.5	4.7	5.7	6.5	7.3
CCF	13,000	25,000	38,000	50,000	61,000	71,000	79,000

2.4 Incentives

All residential electric customers and commercial customers of LG&E or KU with qualifying central air conditioning equipment will be eligible to participate. In conjunction with a central air conditioning system, customers with electric water heaters or pool pumps will also be eligible. In some areas, paging communications are not reliably available and the program is not offered to those customers.

Switch Option - A residential customer with central air conditioning will receive $20 per year for each air conditioning unit participating in the switch option. Commercial customers receive $20 for units up to 5 tons and a larger amount for larger units. Those air conditioning customers with a qualifying water heater or pool pump will receive an additional $8 per year, per unit to participate.

Programmable Thermostat Option - Customers choosing the programmable load control thermostat option will not receive an annual credit for air conditioning units controlled, but will receive $8 per year for eligible electric water heaters and pool pumps.

Multi-family Option – Multi-family units are eligible. We have had great success in working with property owners and managers to enroll entire complexes. The incentive is reduced to $16 per year for each air conditioner, and is split between the property owner and the tenant.

2.5 Implementation Plan

This program proposes to continue to install load control switches and load control programmable thermostats on central air conditioners of an additional 100,000 residential 5,000 commercial air conditioners between 2008 and 2014.

The system employs a one-way commercial paging message to activate devices connected to the participating customers' appliances. The Companies will communicate with the load control devices during system peak hours and during emergency situations to modify the duty cycle of the appliance.

The flexibility of the system allows a customer who experiences discomfort to remain in the program and to participate in a less aggressive cycling strategy. The device can be reprogrammed without requiring a site visit. We have moved several hundred customers from the normal cycling rate to this lower level of cycling and avoided removing devices as a result. At the time of this filing, cumulative switch removals have been less than 2% of total installations.

Participating customers see very little if any kWh savings as a result of load management with the switch option. In the case of air conditioning, the internal air temperature of the house as well as the thermal mass of the structure may increase slightly over a cycling control period. When the air conditioning unit is no longer controlled, this thermal energy is removed from the structure resulting in the "payback" of the small energy savings attributed to the increased internal temperature.

The addition of the programmable load control thermostat should result in demand reduction as well as energy savings for customers choosing to use the setback functions of the thermostat.

Historically the program's most significant means of promotion has been direct mail. While we will continue to use this cost effective means, we will increase our level of referrals from the existing programs and new programs. As market penetration has increased, word of mouth promotion has become prevalent. We will also continue to use information put on customer bills and newsletters, the Companies' web site, and new grassroots promotion channels through groups and organizations.

2.6 Program Budget

Demand Conservation - Residential	2008	2009	2010	2011	2012	2013	2014
Direct Program Labor	$217,110	$223,377	$229,828	$236,467	$243,300	$250,332	$257,571
Office Supplies & Expenses	$15,375	$15,683	$15,996	$16,316	$16,642	$16,975	$17,315
Data Processing	$50,000	$20,910	$21,328	$21,755	$22,190	$22,634	$23,086
Advertising	$540,000	$540,000	$630,000	$490,000	$560,000	$400,000	$320,000
Outside Services/install	$2,842,256	$2,908,629	$2,976,519	$2,569,505	$2,628,758	$2,193,649	$1,990,556
Equipment	$3,484,033	$3,553,513	$3,624,383	$2,973,978	$3,033,257	$2,341,832	$2,005,005
Switch Maintenance	$385,952	$475,245	$569,549	$650,762	$736,334	$807,018	$871,270
Customer Incentives	$2,200,400	$2,376,800	$2,553,200	$2,690,400	$2,827,600	$2,925,600	$3,004,000
Market Research	$30,000	$20,000	$20,000	$20,000	$20,000	$20,000	$20,000
Program Evaluation	$80,000	$40,000	$80,000	$40,000	$80,000	$40,000	$80,000
Switch to T-stat	$146,000	$73,000	$73,000	$73,000	$73,000	$73,000	$73,000
Total Program Expenses	**$9,991,125**	**$10,247,157**	**$10,793,803**	**$9,782,181**	**$10,241,082**	**$9,091,041**	**$8,661,803**

2.6.2 Commercial

Demand Conservation - Commercial	2008	2009	2010	2011	2012	2013	2014
Direct Program Labor	$44,652	$45,930	$47,245	$48,599	$49,991	$51,424	$52,899
Office Supplies & Expenses	$2,050	$2,091	$2,133	$2,175	$2,219	$2,263	$2,309
Data Processing	$2,050	$2,091	$2,133	$2,175	$2,219	$2,263	$2,309
Advertising	$24,000	$24,000	$28,000	$28,000	$28,000	$24,000	$20,000
Outside Services/install	$104,117	$106,513	$108,964	$111,469	$105,183	$98,559	$91,584
Equipment	$144,176	$147,009	$149,899	$152,847	$140,221	$127,030	$113,257
Switch Maintenance	$6,665	$9,253	$11,991	$14,884	$17,613	$20,157	$22,492
Customer Incentives	$53,400	$61,800	$70,200	$78,600	$85,950	$92,250	$97,500
Market Research	$25,000	$0	$0	$0	$0	$0	$0
Program Evaluation	$30,000	$0	$30,000	$0	$0	$30,000	$30,000
Switch to T-stat	$0	$0	$0	$0	$0	$0	$0
	$436,110	**$398,688**	**$450,564**	**$438,750**	**$431,397**	**$447,948**	**$432,350**

Assumptions

- Program labor assumes 1.85 FTE
- Advertising expense is based on $30 per participant, increasing to $40 per participant over the course of the program
- Outside services provides for installation of switches at $75 each and thermostats at $80 each plus $30k annual paging expenses
- Equipment cost based on $72/switch and $178/ thermostat plus testing equipment

- A switch maintenance component includes performing a quality assurance check on 10% of installed switches each year
- Incentives for the switch option are \$20 per air conditioning unit and \$8 per water heater or pool pump each year for residential, and \$30 per year for commercial air conditioners
- Existing "switch" customers will be charged a \$40 fee to have the switch removed and change to the thermostat option

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 5

RESPONSIBLE PERSON: Geoffrey M. Young

Request 5.

On page 14, lines 9-12, you say that Kentucky's "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." You also state, on page 15, lines 19-20, that "DSM is generally a much cheaper energy resource than building new power plants." Please identify the specific DSM or end-use efficiency programs that are much cheaper than Kentucky's newer coal-fired plants. Please provide copies of the studies that support the assertion that these programs are much cheaper than Kentucky's newer coal-fired plants, and that quantify the costs of these programs. Please provide documented examples of how these specific programs have led, in actual practice, to energy services that are much cheaper than Kentucky's newer coal-fired plants, and that quantify the costs of these energy services.

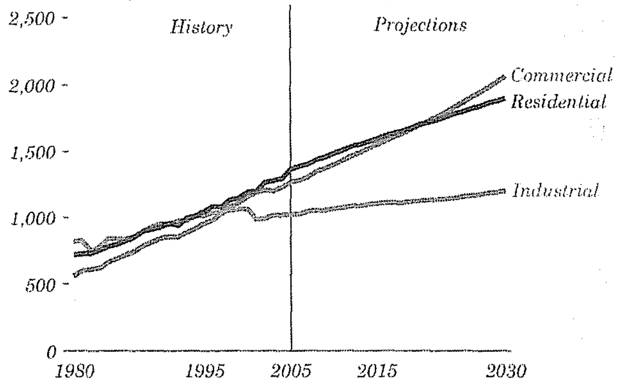
Response 5.

According to the U.S. Energy Information Administration (EIA), the levelized cost of "advanced" new coal-fired generating plants is between 5 and 6 cents per kWh. [Source: http://www.eia.doe.gov/oiaf/aeo/index.html] The relevant two pages from this report are provided below.

In contrast, the levelized cost of saved energy for DSM programs is between 0.6 and 3 cents per kWh. For extensive documentation of the latter point, please refer to my response to the first information request of the Commission Staff, request 3.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 53. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)



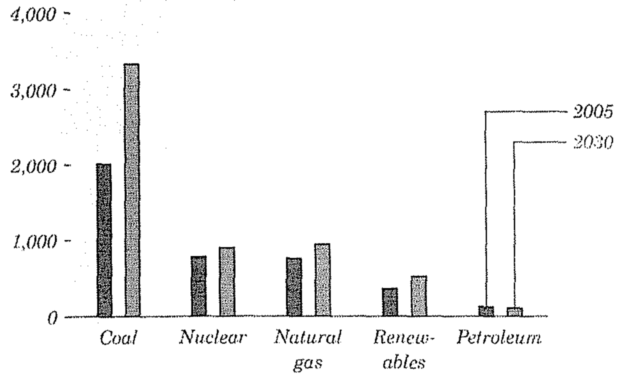
Total electricity sales increase by 41 percent in the *AEO2007* reference case, from 3,660 billion kilowatthours in 2005 to 5,168 billion kilowatthours in 2030. The largest increase is in the commercial sector (Figure 53), as service industries continue to drive growth. Electricity sales, which are strongly affected by the rate of economic growth, are projected to grow by 54 percent in the high growth case, to 5,654 billion kilowatthours in 2030, but by only 28 percent in the low growth case, to 4,682 billion kilowatthours in 2030.

By end-use sector, electricity demand in the reference case is projected to grow by 39 percent from 2005 to 2030 in the residential sector, by 63 percent in the commercial sector, and by 17 percent in the industrial sector. Growth in population and disposable income is expected to lead to increased demand for products, services, and floorspace, with a corresponding increase in demand for electricity for space heating and cooling and to power the appliances and equipment used by buildings and businesses. Population shifts to warmer regions will also increase the need for cooling.

The growth in demand for electricity is expected to be potentially offset by efficiency gains in both the residential and commercial sectors, and higher energy prices are expected to encourage investment in energy-efficient equipment. In both sectors, continuing efficiency gains are expected for electric heat pumps, air conditioners, refrigerators, lighting, cooking appliances, and computer screens. In the industrial sector, increases in electricity sales are offset by rapid growth in on-site generation.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 54. Electricity generation by fuel, 2005 and 2030 (billion kilowatthours)



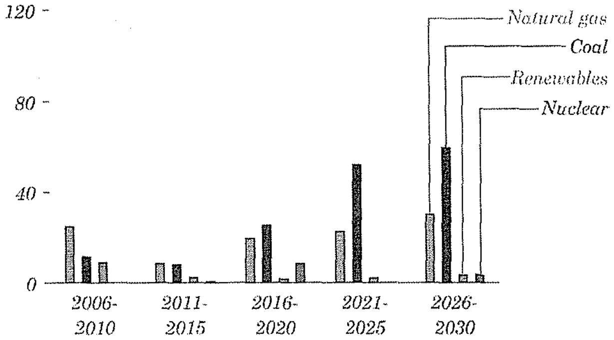
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to supply most of the Nation's electricity through 2030 (Figure 54). In 2005, coal-fired plants accounted for 50 percent of generation and natural-gas-fired plants for 19 percent. Most capacity additions over the next 10 years are natural-gas-fired plants, increasing the natural gas share to 22 percent and lowering the coal share to 49 percent in 2015. As natural gas becomes more expensive, however, more coal-fired plants are built. In 2030, the generation shares for coal and natural gas are 57 percent and 16 percent, respectively.

Nuclear and renewable generation increase as new plants are built, stimulated by Federal tax incentives and rising fossil fuel prices. Nuclear generation also increases modestly with improvements in plant performance and expansion of existing facilities, but the nuclear share of total generation falls from 19 percent in 2005 to 15 percent in 2030. The generation share from renewable capacity (about 9 percent of total electricity supply in 2005) remains roughly constant at about 9 percent.

Relative fuel costs, particularly for natural gas and coal, affect both the utilization of existing capacity and technology choices for new plants. Natural-gas-fired plants are projected to provide 27 percent of total electricity supply in 2030 in the low price case but only 11 percent in the high price case, while the projected share of total generation from coal-fired plants is 45 percent in the low price case but increases to 61 percent in the high price case. Changes in environmental policies would also affect the *AEO2007* projections for capacity additions.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 55. Electricity generation capacity additions by fuel type, including combined heat and power, 2006-2030 (gigawatts)



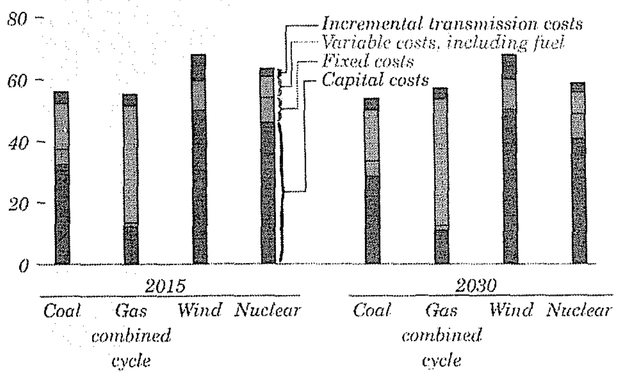
In the reference case, 292 gigawatts of new generating capacity (including end-use CHP) is required by 2030 to meet growth in electricity demand and to replace inefficient, older generating plants that are retired. Capacity decisions depend on the costs and operating efficiencies of different options, fuel prices, demand growth, and the availability of Federal tax credits for investments in some technologies.

Coal-fired capacity, which typically is expensive to build but has relatively low operating costs, accounts for about 54 percent of the total capacity additions from 2006 to 2030 (Figure 55). Natural-gas-fired plants, which generally are the least expensive capacity to build but have comparatively high fuel costs, represent 36 percent of the projected additions. Renewable and nuclear plants, which have high investment costs and low operating costs, account for 6 percent and 4 percent of total additions, respectively. Of the 12 gigawatts of new nuclear capacity expected by 2030, 3 gigawatts is added after the EPACT2005 PTC expires in 2020.

Different fuel price paths or growth rates for electricity demand can affect the quantity and mix of capacity additions. In the low and high price cases, variations in fuel prices have little impact on total capacity additions but do affect the mix of capacity types. Because fuel costs are a larger share of total expenditures for new natural-gas-fired capacity, higher fuel prices lead to more coal-fired additions. In the economic growth cases, capacity additions range from 191 gigawatts in the low growth case to 398 gigawatts in the high growth case, but with similar shares for the different generating technologies in both cases.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 56. Levelized electricity costs for new plants, 2015 and 2030 (2005 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 56) [*167*]. The *AEO2007* reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the risks of siting new units.

Capital costs decline over time (Table 16), at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The efficiency of new plants is also assumed to improve through 2015, with heat rates for advanced combined cycle and coal gasification units declining from 6,572 and 8,309 Btu per kilowatthour, respectively, in 2005 to 6,333 and 7,200 Btu per kilowatthour in 2015.

Table 16. Costs of producing electricity from new plants, 2015 and 2030

	2015		2030	
Costs	***Advanced coal***	***Advanced combined cycle***	***Advanced coal***	***Advanced combined cycle***
	2005 mills per kilowatthour			
Capital	32.64	12.16	28.71	11.12
Fixed	4.89	1.44	4.89	1.44
Variable	14.82	37.97	16.49	41.17
Incremental transmission	3.72	3.67	3 64	3.49
Total	**56.07**	**55.24**	**53.73**	**57.22**

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 6

RESPONSIBLE PERSON: Geoffrey M. Young

Request 6.

Reference Page 14 of your testimony. On Line 12 you make that statement that; "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." Is Mr. Young suggesting that EKPC has not employed the lowest cost strategy for managing changes in base rates, in light of the fact that its last base rate case increase occurred 23 years ago, in 1984? Please explain your response.

Response 6.

Yes. The conclusion I referred to above, to the effect that improved end-use efficiency is much less expensive than expanding energy supply, has been well-known for the past 30 years. If EKPC and its member coops had started implementing a strategy 30 years ago designed to help their ultimate customers obtain energy services at the lowest total resource costs, their investment in energy-saving programs and technologies would have been substantially higher and their investment in new generation plants substantially lower. It is likely that demand growth during that period could have been eliminated or transformed into a decrease. New coal-fired power plants would not be under construction or in the planning stages today, with all the imminent and dramatic impact on rates that they entail. EKPC would instead be thinking about the question of which of its old, dirty, coal-fired generating units should be retired first. Base rates would be lower for all customers, and the average bill per customer would be substantially lower. It is likely that the economic health of the areas served by the EKPC system would be noticeably better than it is today.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 7

RESPONSIBLE PERSON: Geoffrey M. Young

Request 7.

Beginning at line 23 on page 14, you say that: "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." Please identify and provide copies of the studies or other evidence that support these assertions.

Response 7.

The documentation for this conclusion was provided in Attachment A of my testimony. Adding up the numbers in the column labeled, "MWh saved in 2006" yields a result very close to zero. Adding up the numbers in the column labeled, "demand reduction in 2006, MW" yields a total of approximately 60 MW. Some of this reduction in demand is a result of the Electric Thermal Storage (ETS) program for homes with electric furnaces, although it is not possible to know how much because the data for this program is combined with that of the ETS program that displaces propane. To the extent that some of the 60 MW demand reduction is a result of the ETS electric furnace program, it would be accurate to conclude that there has been "some shifting of demand from peak load periods to off-peak periods."

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 8

RESPONSIBLE PERSON: Geoffrey M. Young

Request 8.

On page 24, line 22, you refer to "legitimate DSM program costs." Please provide examples of "legitimate DSM program costs." Is there also such a thing as "illegitimate DSM program costs"? If so, please provide examples of "illegitimate DSM program costs," and please indicate how large a potential problem is posed by "illegitimate DSM program costs".

Response 8.

"Legitimate DSM program costs" are investments by EKPC and its member coops that contribute to the goals of helping customers save energy or shift demand in a cost-effective manner. Although I have not performed a detailed analysis of EKPC's existing DSM programs, I have no a priori reason to believe that its program costs for the following programs are anything but legitimate: Geothermal Heating and Cooling, Air-Source Heat Pump Retrofit, Tune-Up HVAC Maintenance, Button-Up Weatherization, Compact Fluorescent Lighting, the Touchstone Energy Home programs, Dual-Fuel Air-Source Heat Pump with Propane Retrofit, Commercial Efficient HVAC, and Industrial Premium Motors. Although it may well be possible to expand the scope and improve the effectiveness and cost-effectiveness of these programs, it would be difficult to make a case that EKPC's investments in these programs have been "illegitimate."

I think of "illegitimate" expenditures as representing either DSM programs that are designed primarily to build load and are therefore more properly termed "marketing programs," or DSM programs that have been "gold-plated" by significant expenditures on items that are wasteful or clearly excessive.

The magnitude of the problem of DSM expenditures on load-building or marketing programs appears to be significant at EKPC at this time, unfortunately. I conclude that primarily because the load-building impact of the ETS programs has approximately negated the energy-saving impacts of EKPC's other DSM programs.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 9

RESPONSIBLE PERSON: Geoffrey M. Young

Request 9.

On page 35, you propose that QF prices be set low for highly polluting generation technologies and that they be set high (perhaps through net metering) for environmentally sound generation technologies. On page 36, you define an "environmentally sound generation technology" as "a generating technology that causes less environmental damage per delivered kWh than EKPC's existing fleet of generating units."

Request 9a.

How do you define "highly polluting generation technologies"?

Response 9a.

Certain generation technologies are very likely to cause serious damage to human health and the environment simply as a result of the fuel burned and the lack of pollution control technologies used. Examples would be generating units burning coal or petroleum without any pollution controls at all.

For purposes of this case, I would define "highly polluting generation technologies" as technology/fuel combinations that cause significantly more environmental damage than that caused by EKPC's existing fleet of generating units per delivered kWh.

Request 9b.

Given that the environmental damage arising from each generating technology depends upon that technology's particular mix pollutants, wildlife impacts, and so forth, how do you propose to measure the "environmental damage" due to each type of generating technology?

Response 9b.

One possible way to standardize the impacts of various technology/fuel combinations would be to estimate the additional number of human deaths that are likely to occur prematurely as a result of the emission of certain pollutants into the atmosphere of Kentucky. It is also possible to assign monetary values to the number of productive employment years lost by people who would be exposed to the pollutants.

The attached article from the *Electricity Journal* contains data about the emissions characteristics of certain distributed generation technologies. [Greene, Nathanael and Roel Hammerschlag, "Small and Clean Is Beautiful: Exploring the Emissions of Distributed Generation and Pollution Prevention Policies," *Electricity Journal*, June 2000, pages 50-60. It would be possible for the Commission to develop an overall index that combines the emissions of NOx, SOx, CO and PM-10 into a single index number. If a proposed qualifying facility were to emit 30% less or 40% less pollution per kWh, as measured by the combined index number, than EKPC's average emissions per kWh, it would be considered an "environmentally sound" technology and would become eligible for the favorable terms included in the QF tariff.

Small and Clean Is Beautiful: Exploring the Emissions of Distributed Generation and Pollution Prevention Policies

Unless steps are taken now, the success of distributed generation could prove to be its own worst enemy by contributing significantly to urban smog and the concentration of greenhouse gases.

Nathanael Greene and Roel Hammerschlag

Nathanael Greene *is an Energy Policy Analyst at the Natural Resources Defense Council in New York, where he specializes in energy policy issues, including utility restructuring, energy taxes, energy efficiency, renewables and low-income service. He holds a B.A. in Public Policy from Brown University and an M.S. in Energy and Resources from the University of California at Berkeley.* **Roel Hammerschlag** *serves as a Physics and Engineering Consultant to the NRDC and is currently founding the Institute for Lifecycle Analysis in Seattle. He holds a B.S. in Physics from the Massachusetts Institute of Technology.*

In the past few years, the proponents of distributed generation have made a growing number of excited claims that small generators will revolutionize the electricity generation sector and have an enormous environmental payoff. In these predictions, people usually cite wind, solar, fuel cells, microturbines, and occasionally in quieter tones, the existing installed base of diesel generators.[1]

Proponents envision a future in which distributed generators are as ubiquitous as boilers. Homeowners and businesses would buy these small generators and have them installed just as they would any other appliance. In these visions, distributed generators become so common that they either replace the current electric grid altogether or enhance electric reliability to near perfection.

The excitement has attracted enough political attention to support the passage of net metering laws in more than half the states; launch interconnection regulatory proceedings in California, New York, and Texas; and convince the Clinton administration to draft legislation calling for national interconnection standards. The $217 billion American market for electricity[2] certainly provides a

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strong motivation for distributed generation manufacturers to try to make their product ubiquitous.

Unfortunately, the family of technologies that constitute distributed generation has a decidedly mixed environmental profile. Some technologies—such as wind and solar—are without a doubt very clean. Others—such as diesel internal combustion engines (ICEs)—are not. Furthermore, the environmental performance of distributed generation is for the most part unregulated. Federal emissions regulations generally only cover non-utility generators down to approximately 1 MW in size. Some state permitting requirements affect smaller generators located in non-attainment areas, but generally regulations and enforcement of emission limits for generators below 1 MW are spotty at best.

Given the size of the electricity market, the range in emissions, and the lack of regulation in this area, there is clearly the potential for a literal thousand points of light to become a thousand points of soot. If just 0.5 percent of the U.S. demand for electricity were met by uncontrolled diesel engines, the country's annual nitrogen oxide (NO_x) emissions could increase by nearly 5 percent.[3] The impact would be even starker if distributed generation displaced only the new, clean combined-cycle natural gas turbines.

Of course, this worst-case scenario is hardly inevitable. The market for distributed generation faces many barriers, not the least of which is the resistance of electric distribution utilities to losing sales. Furthermore, distributed generation will not be represented solely by uncontrolled diesel engines, but rather by a host of technologies, many of which will include measures that can significantly mitigate their emissions.

Distributed generation has the potential to reduce air pollution, provide high-reliability electricity, and reduce the cost of energy—but only if states and the federal government adopt the right package policies. In this article, we present a simplified comparison of combined cycle turbines to uncontrolled distributed generation, to highlight the need for environmental regulations as part of this package of policies. If the key players—the industry, environmental community, end-users, and state and federal regulators—work together now, we can reap all the promises distributed generation has to offer.

There is clearly the potential for a literal thousand points of light to become a thousand points of soot.

I. The Technologies

We define distributed generation as electric generation intentionally located near a load that will use all or most of the energy generated. A homeowner meeting a portion of his or her demand with a 2 kilowatt (kW) photovoltaic system is using distributed generation, as is a major energy company building a 50 MW power plant exclusively to serve an industrial park. However, because systems above approximately 1 MW are regulated at the federal level, a shift from central generation to large distributed technology should be largely environmentally neutral. Here we are focused on smaller equipment that has the potential to fly below existing regulation and, in large numbers, to produce substantial environmental impacts.

Below 1 MW, the technologies we are concerned with are photovoltaics, wind turbines, fuel cells, biomass, microturbines, and ICEs fueled by natural gas or diesel. All of these technologies are either available today or expected to be available by 2003. Note also that we are only addressing distributed generation and not all distributed resources, which would include energy efficiency, by far the cleanest and most cost-effective option available.

Photovoltaics and **wind turbines** are currently on the market and used to generate electricity. Since neither technology combusts or reforms fossil fuels, they produce no significant air emissions.

Fuel cells are actually a family of technologies, each with a different mode of operation, though all with the same fundamental chemical reaction at their core. Fuel cells technically need only hydrogen and oxygen to operate, but for the foreseeable future, they will run on the hydrogen provided in a hydrocarbon carrier, such as methane. The process for extracting the hydrogen from the carrier, known as reforming, generates air emissions. One fuel cell model is currently on the market, and several others are due to be released in one to three years. Some of the designs expected to become commercial are similar to combined cycle turbines in that they extract energy from the fuel in two distinct stages. These fuel cells are expected to have higher efficiencies.

Biomass is a catchall term that can refer to a range of fuels and generators. At the scale with which we are concerned, the term usually refers to an ICE or microturbine powered by gasified wood or animal waste. However, fundamental research toward direct combustion of wood or similar solids is underway and may result in distributed generation-scale biomass boilers within the next decade.[4] If the fuel used for any of these processes is a crop that was specifically cultivated for energy generation, then burning it creates no net increase in carbon concentrations, though it can create other air pollutants. In this article, we have modeled biomass as either fluidized-bed combustion of dry wood or gasification of biomass into methane and combustion in a low-emission combustion engine.

Microturbines are scheduled to enter the mainstream during the next three years. Generally less than 100 kW in size, these high-speed, single-rotor turbines combust natural gas and therefore generate air emissions.

Though **internal combustion engines** can burn a wide variety of fuels, we focus on two of the most common types used for electric generation: diesel fuel (compression–ignition) and natural gas (spark–ignition). The air emissions are dramatically different based on the type of fuel burned. Also, some natural gas engines are designed specifically with characteristics to reduce air emissions, most notably a lean fuel-air mixture; these are known as "low emissions" engines.

Some states regulate small generators more strictly, or lower the threshold for requiring new source review.

II. Air Permitting Regulations

The Clean Air Act and resulting regulations established performance standards for various types of generating technologies. These standards use fuel input to determine the lower limits of the generators covered. Assuming 30 percent conversion efficiency, these standards cover steam generating units and stationary gas turbines down to about 1 MW.[5]

The 1990 amendments to the Clean Air Act created the New Source Review requirement, which requires Title V permitting of all "major sources." This designation is given to any unit that emits more than 10 tons per year of any hazardous air pollutant, such as mercury, or more than 100 tons per year of any criteria air pollutant, such as sulfur dioxide (SO_2) or NO_x. In non-attainment areas, the limits for criteria pollutants can be substantially lower depending on the severity of local pollution problems.[6]

In the one "extreme" ozone non-attainment area in the United States–Los Angeles–a generator would have to go through new source review if it had the potential to emit more than 10 tons per year of NO_x or volatile organic compounds. In "severe" non-attainment areas such as New York City or Chicago, generators can emit up to 25 tons per year before coming under Title V. In these areas, a 500 kW diesel or natural gas engine emitting 20 lbs/MWh of NO_x could run for nearly 60 percent of a year before being designated a major source. In other words, federal regulations do not apply to any but the dirtiest small generators running in the most restricted areas.

Some states regulate small generators more strictly, or lower the threshold for requiring new source review. In practice in New York City, engines are automatically exempt from permitting if they are smaller than about 150 kW.[7] Other types of generators are exempt if they use less than 10 mmBtu/hr fuel. This is about the amount of fuel an 800 to 900 kW generator would use, depending on its efficiency. However, a requirement for an air permit does not mean that emissions will have to be controlled. In New York, if a generator is large enough to require a permit, but not large enough to be governed by Title V, the generator may have to monitor its emissions but will not have to restrict them.

California has taken a different approach in the Los Angeles area, establishing lower size requirements for permitting, and emissions restrictions for permitted equipment. The South Coast Air Quality Management District's (SCAQMD) rules require engines as small as about 40 kW to limit emissions of NO_x to about 1.6 lbs/MWh.[8]

Notwithstanding these efforts, existing air regulations would not prevent small generators from developing into a substantial source of air pollution. Whether this happens depends entirely on the policies put in place to encourage distributed generation and to control its emissions.

III. Comparing Distributed and Central Generation

In our comparison of electric generation technologies we selected pollutants from three categories: those that have local, regional, and global impacts. The local impact pollutants are particulate matter smaller than 10 microns (PM-10), CO, and NO_x. These pollutants all exacerbate pulmonary conditions like asthma. CO is poisonous to humans at high concentrations. PM-10 and NO_x both play a role in smog formation. Regional impact pollutants include NO_x and SO_2. NO_x contributes to nitrogen loading in water bodies. SO_2 and NO_x both contribute to acid rain, which destroys ecosystems and accelerates the corrosion of buildings and monuments.[9] The global impact pollutant is carbon dioxide (CO_2), which causes climate change.

Generally, the best-case emissions claims are manufacturers' published claims and the worst case is field test data.

We have compared emissions on an output basis, in pounds of pollutant per MWh generated. For this reason, the efficiency of each technology—the ratio of electric energy output to fuel energy output—is a critical factor. For any one type of generator burning a single type of fuel, greater efficiency means less fuel consumption and generally less pollution for a given amount of electricity. Less fuel consumption also translates directly into low CO_2 emissions.

We also separately present the emissions of combined cycle turbines augmented by 10 percent to account for line losses. Due to line losses, 1 kW of distributed generation displaces more than 1 kW of central generation. Ten percent is higher than average system line losses but often less than marginal line losses. We use the figure here as a rough estimate of one guaranteed benefit of distributed generation.

Table 1 provides an overview of the cost, efficiency, and emissions characteristics of the major distributed generation technologies. Where possible, we present a range from the best case to worst case. Generally, the best-case emissions are manufacturers' published claims and the worst case is field test data. The manufacturers' claims are usually based on new equipment running under ideal conditions. In fact, some claims are based on forecast improvements due to advanced technology. Many of the lowest emission levels are only anticipated to be achievable by 2003 and are not currently available on any commercial model. Indeed, many of these low emission rates will probably not develop absent regulations mandating a market for cleaner machines. For microturbines and fuel cells, we do not have field data and so rely only on manufacturers' claims. Experience has shown that real-world operating conditions result in higher emissions and lower efficiency. Thus, while all of the technologies will get cleaner over time, the ranges for microturbines and fuel cells are probably less predictive of actual performance in the next few years.

The Energy Information Administration forecasts that the demand for electricity in the

United States is going to continue to expand during the next 20 years.[10] This increasing demand, coupled with the closure of aging power plants, ensures that plenty of new capacity will be built in the upcoming decades. If distributed generation does not step in and fill this demand, then more central generation will fill it instead. The most common prime mover for new central generation plants will undoubtedly be the combined-cycle natural gas turbine, whose popularity has been increasing exponentially over the last 20 years.[11] Thus, the last row of Table 1 presents this technology as the reference case.[12]

The emissions from the distributed generation technologies are presented as uncontrolled, reflecting the current lack of regulations for generators of this size. Decisions about these technologies will be made purely on economics, and thus few if any tailpipe controls should be expected. The combined-cycle turbine emissions listed in Table 1 are controlled emissions because all new central generation plants are regulated.[13] Again, the range of emissions presented here represents the difference between manufacturers' claims and field test data.

Looking at each pollutant, we can create three categories of environmental performance for distributed generators: (1) much better than a combined cycle gas turbine, (2) about the same, and (3) much worse. The results of this comparison appear in **Figure 1.** The three categories are calculated from Table 1 by looking for any overlap between the emissions ranges for each distributed technology with the ranges presented for combined cycle turbines plus 10 percent line loss. While this will not measure the absolute environmental impact of various technologies, it will separate the technologies that will undoubtedly improve the environment from those that will have a neutral or negative impact.

Looking across the range of technologies and pollutants, the clear

Table 1: Distributed Generation Emissions Data for Uncontrolled Electric Generators Sized under 1 MW[a]

Device Type	Fuel	Specific Cost $/kW[c]	Efficiency % At HHV[d]	Emissions in lb/MWh[b]				
				CO_2	NO_x[e]	SO_2[f]	CO[e]	PM-10
ICE[g]	Diesel	300–1,000	33–42	1,300–1,700	10–41	0.4–3	0.4–9	0.4–3
ICE, stoic[g]	NG	300–1,000	33–42	950–1,200	18–53	negl.	1–6	~0.6
ICE, LE[g]	NG	500–1,200	35–41	980–1,100	0.3–6.0	negl.	2–9	~0.6
Microturbine	NG	650–850	22–30	1,300–1,800	0.2–1.4	negl.	0.3–1.8	>0.03
Fuel cell	H from NG	3,000–4,000	29–50	800–1,400	<0.05	0	0.01–0.12	negl.
Biomass[h]	Gas/wood	tbd	30–41	0–2,300[i]	0.3–6.0	<0.3	2–9	0.6–4
Photovoltaic	Sunlight	5,000–12,000	n/a	0	0	0	0	0
Wind	Wind	850–3,500	n/a	0	0	0	0	0
New CC Turbine[j]	NG	500–870	48–57	700–830	0.11–0.9	negl.	0.05–1.0	0.03–0.3
with 10% line loss				770–920	0.13–1.0	negl.	0.05–1.1	0.03–0.3

[a] Data are limited to products currently on the market or expected to be on the market by Jan. 1, 2003; wood-burning biomass may be an exception.
[b] All values are rounded to one or two significant figures.
[c] Cost of distributed generation equipment does not include emissions controls.
[d] Percent efficiency, measured with respect to the fuel's higher heating value.
[e] Combustion can often be tuned for either low NO_x or low CO emissions, thus it is unlikely that uncontrolled combustion equipment will achieve the low end of the ranges presented for both these pollutants.
[f] Sulfur is present in natural gas at 0.0006 percent, but is assumed to be 0 for fuel cells due to filtering. Sulfur in diesel is assumed to range from 500 ppm for road fuel to 3000 ppm for nonroad fuel.
[g] ICE, internal combustion engine; LE, tuned for low emissions; Stoic, stoichiometric, which is the standard tuning.
[h] Biomass ranges are equal to those for a LE ICE extended as appropriate to include emission levels from fluidized-bed combustion of dry wood.
[i] 0 is the theoretical minimum when accounting for fully renewable biomass.
[j] Central generation reference condition. >100 MW new combined-cycle natural gas turbine with at least steam-injection NO_x control.

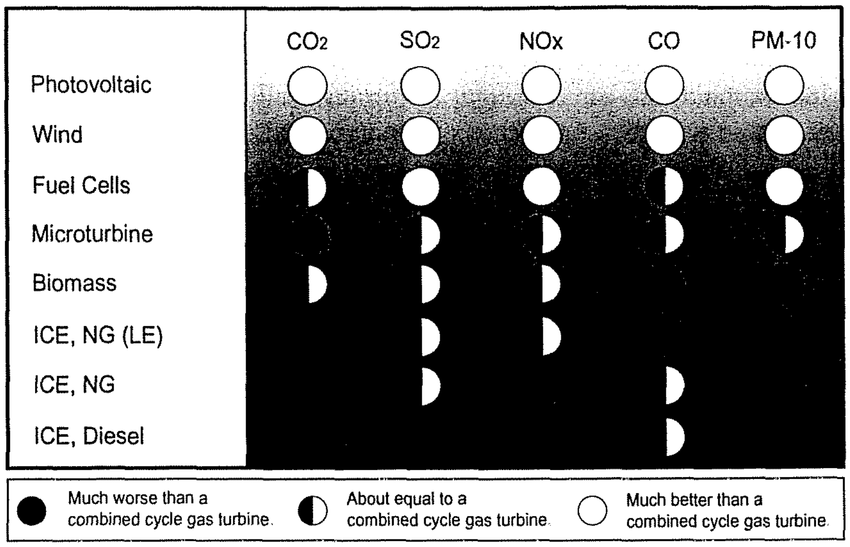


Figure 1: Comparison of Uncontrolled Distributed Generation Emissions Relative to Combined Cycle Turbines

superiority of photovoltaics and wind is easy to see. Conversely, the poor environmental performance of the uncontrolled ICEs is also obvious. While microturbines have been touted as a new and cleaner technology, they are similar to a miniaturized simple-cycle turbine, so it should be no surprise that their emissions are not an improvement over full-scale combined-cycle turbines.

Biomass and fuel cells fall into an interesting middle grouping, though for different reasons. Fuel cells are generally much cleaner than combined cycle plants with the notable exception of CO_2. Given the seriousness of global warming, a fuel cell's emissions of CO_2 must not be overlooked. Conversely, biomass has the potential to have zero CO_2 emissions, but on a distributed generation scale is likely to have substantially higher emissions of most other pollutants.[14] In other words, how one views these two technologies depends on whether one is more concerned by climate change or by local and regional impacts.

IV. Why Distributed Generation Can Have a Large Environmental Impact

A. Efficiency of Scale

Larger versions of any particular type of generator tend to be more efficient at turning fuel into electricity. As explained earlier, the less fuel a technology has to burn to produce a kilowatt-hour of electricity, the less pollution it will produce.

Figure 2 presents the relationship between efficiency and size for a range of fossil fuel technologies. Efficiency of scale is a factor for nearly every technology available.[15] Indeed, the efficiencies tend to ramp down especially steeply at the smallest available sizes.

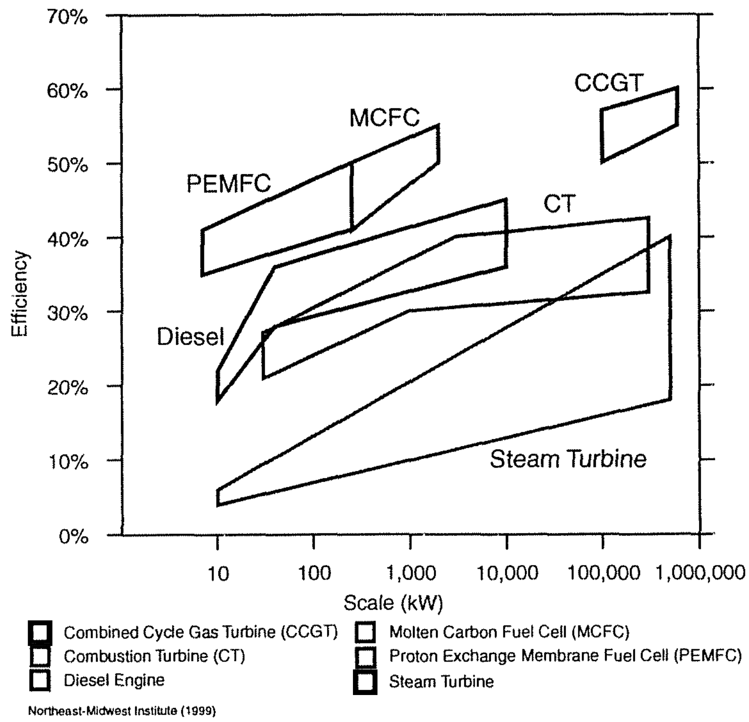


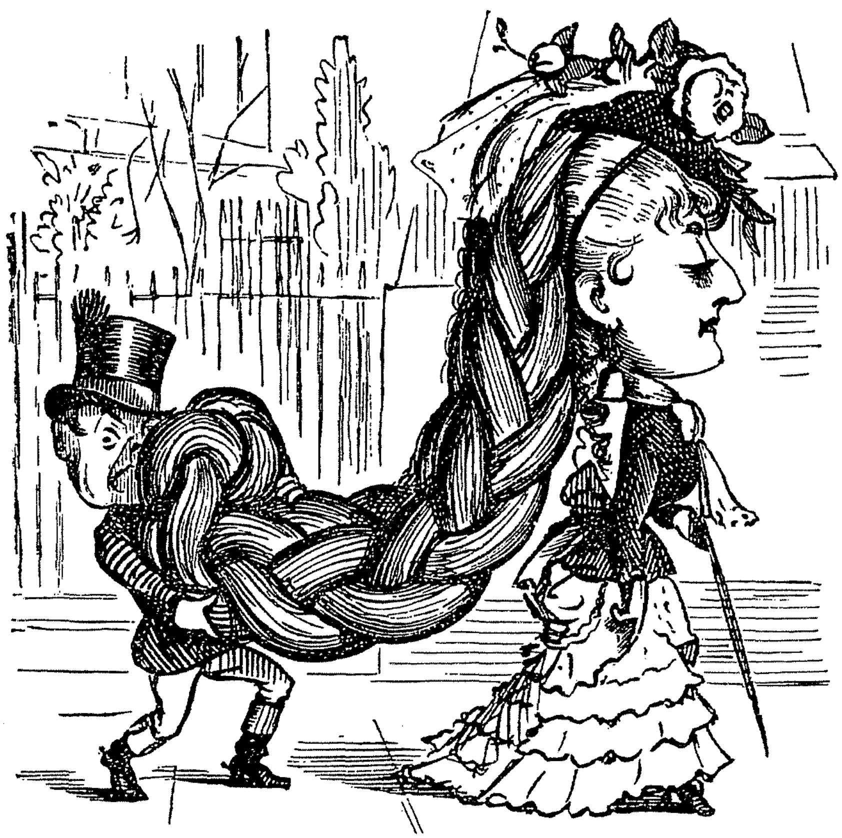
Figure 2: Efficiency versus Size for Seven Technologies

B. Central Generation Plants Have Superior Regulation and Maintenance

The larger scale of central generation boasts several more environmental advantages besides the pure generating efficiency. First, since these larger plants are regulated, federal law requires that they monitor their emissions and meet certain emissions requirements on an ongoing basis. Second, fitting plants with best available control technology can be financially feasible on a large scale, but not on a small scale. Third, and perhaps most important, a large central generating plant will be constantly staffed by maintenance workers monitoring the plant's efficiency and emissions control equipment.

C. Proximity of Local Pollutants

Proximity to load, one of distributed generation's most advantageous features, can also work against it. Whether the load is home appliances or commercial air conditioning, the load is likely to be close to people, and thus the generator and its emissions are likely to be at ground level or on rooftops. This is in stark contrast to central generation plants that are generally located away from densely populated areas and emit their exhaust through tall stacks. Thus, pollution from the two sources is not created equal.



Proximity to load can also work against it.

V. Mitigating Environmental Impact

Though many distributed generation technologies are environmentally harmful if uncontrolled, a number of measures exist to mitigate the impacts. Policymakers should encourage these measures wherever possible, and especially in states that are actively encouraging distributed generation. As states adopt streamlined interconnection procedures, they should tailor system benefits charge funds, tax incentives, and net metering laws to favor installations that take advantage of these measures. Some states have already started down this path. Distribution utilities also have an important role to play in ensuring that distributed generation goes where it can do the most good in both economic and environmental terms.[16]

A. Favor the Cleanest Technologies

Photovoltaics and wind turbines have no air emissions and, when properly sited, minimal environmental impact. These two technologies should always be favored. Fuel cells also deserve support, though as long as they rely on fossil fuel they will not be pollution-free. Still, they provide substantial local and regional environmental benefits over central generation.

B. Take Advantage of Combined Heat and Power

Because distributed generation is by definition co-located with its load, many distributed generation applications are excellent candidates for combined heat and power (CHP) applications. By taking advantage of the heat that would otherwise be wasted, CHP generation improves the efficiency of installations and thus reduces the emission rates. Furthermore, CHP applications should be credited with displacing the emissions that would have otherwise occurred due to the traditional source of heat.

Combined heat and power could greatly mitigate the environmental impacts of fuel cells, biomass, microturbines, and ICEs, all of which generate waste heat when they convert their fuel to electricity. Efficiencies from CHP systems can easily reach 60 percent, and with good design can be as high as 80 to 90 percent. This can mean a reduction in emission rates of between 35 and 50 percent. For example, all of the fuel cells currently installed in New York take advantage of at least some of the system's heat, thus reducing average CO_2 emissions rates from 1,075 to 660 lb/MWh.[17] Indeed, to date most commercial installations of fuel cells have been CHP applications. Given the high initial cost of fuel cells, making use of CHP can improve their overall economics.

From an environmental perspective, combined heat and power applications should be encouraged for all generation technologies including central generation, which can be collocated with major commercial or industrial centers. In fact, CHP can provide greater environmental benefits at large-scale facilities, which are more likely to be highly efficient and well maintained than a small distributed generation installation. As with heating, ventilating, and air conditioning systems, quality of installation is of special

concern: Poor sizing and installation of traditional heating, ventilation, and air conditioning equipment can be responsible for over 25 percent loss in efficiency in commercial and residential buildings.[18] Nevertheless, the benefits of CHP make these challenges well worth tackling.[19]

C. Use Catalysts or Other Post-Combustion Controls

Table 1 cites uncontrolled emissions. The emission rates of CO and NO_x from ICEs and microturbines can easily be reduced by 80 to 98 percent with the addition of a tailpipe catalyst.[20] Particulate controls are available as well. Small-scale catalyst technology is very mature, thanks to its use in the automobile industry. However, the issue of maintenance is again important: How can we ensure that a failing catalyst is detected and replaced by the distributed generation user? In its lifetime, a car would operate between 5,000 and 7,000 hours; a generator operating at 80 percent capacity factor would operate for more hours in a single year.

D. Favor Installations Where Line Loss Would Be High

The one benefit that all distributed generation provides is avoided line losses. Depending on the size, grid loading, and distance between load and generator, line losses can vary from just a few percent up to 20 or 30 percent. Average line losses vary from 5 to 10 percent. However, distributed generation will tend to displace marginal line losses, which can reach 20 to 30 percent. This means that each kWh produced by a distributed generator displaces anywhere from 1.05 to 1.3 kWh of central generation and hence, that much more air pollution that the central generator would have produced.

Greater line losses will be avoided in areas where power has to travel long distances and in crowded areas where transmission and distribution lines are likely to be heavily loaded. Load pockets, which are defined by limited transmission capacity, are likely to be areas of high line loss. Fortunately, the economics of load pockets are also likely to encourage distributed generation.

VI. Where Do We Go from Here?

Consumers who install distributed generators will do so primarily to increase the reliability of their electric service and reduce the cost of electricity. While consumers who are concerned about environmental impacts will help develop the market for cleaner technologies, this does not obviate the need for an air pollution prevention program targeted at distributed generation. Absent accompanying environmental standards, policies designed to promote distributed generation will end up promoting the cheaper, dirtier technologies and thus create a serious environmental problem.

A comprehensive distributed generation policy needs to not only open the markets to new technologies but also address the environmental performance of all technologies in the marketplace. It also needs to encourage proper sizing and installation, and it needs to ensure that emissions control systems are maintained. This suggests a triad of pollution prevention policies: a performance standard, building energy code modifications, and an inspection and maintenance program.

A. Performance Standards

Distributed generators will become as common as boilers and home heating systems only if these technologies are easy to purchase and connect. If this happens, permitting on a unit-by-unit basis will become too time-consuming and expensive. Instead, we should follow the model of the natural gas hot water heater requirements of California's SCAQMD. Under these rules, manufacturers must have each model type tested by an independent lab and certified to meet specified emissions levels. The certification status must be displayed on the nameplate, and the model must be re-certified every three years.[21]

The first step in enabling performance standards is to develop a testing and labeling procedure. By themselves, labels will make it easier for consumers and their contractors to include environmental performance in their purchase decisions. Labels could also be the basis for state measures encouraging many of the previously described mitigating measures. The success of the Department of Energy/Federal Trade Commission appliance-labeling program offers an encouraging example.

Regulators would do well to initiate a collaborative effort among industry, environmental groups, and consumers to address the technical and policy issues regarding performance standards and testing and labeling requirements. Existing organizations may be useful starting points for such an effort. In California, the California Alliance for Distributed Energy Resources (CADER) has already brought together manufacturers, environmentalists, and regulators to explore issues related to distributed generation. The New Jersey Corporation for Advanced Technologies (NJCAT) is a six-year-old public/private partnership developing independent validation and verification programs. NJCAT has recently joined efforts with Canada and the California Environmental Protection Agency to develop a verification process for Ballard's

The certification status must be displayed on the nameplate.

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environmental claims related to its new stationary fuel cell. The Distributed Power Coalition of America could also play a crucial role as the industry association.

There are significant challenges, of course. For instance, emission rates and efficiency will vary with load cycle. Thus a unit run primarily at steady state will generally have lower emissions than the same type run through transient cycles. Similarly, making use of the combined heat and power of a technology will lower the emissions, but different applications can make more or less use of this. Emissions regulations should always be based on output (e.g., lbs./MWh) to encourage efficiency.

B. Building Energy Codes

Given that so much of the actual in-operation efficiency, and thus emissions levels, from a distributed generator will be determined by how well it is sized and installed, decision makers cannot afford to ignore these practices. Building energy codes offer an ideal framework for guidelines. Already, these codes cover everything from the size of heating and cooling systems to the type of windows in a building. They also require testing of systems after installation to ensure performance is at a specified level. And, the codes are already separately tailored for commercial and residential buildings. Simply extending codes to cover the energy use of distributed generation is not enough; for the reasons presented earlier, codes should also be designed to encourage CHP applications. Updating energy codes to cover distributed generation and encourage CHP should be a top priority for all states.

C. Inspection and Maintenance

Studies indicate that a dramatically disproportionate amount of automobile pollution comes from vehicles with engine problems and/or tailpipe control failures. Thus the Clean Air Act mandated

inspection and maintenance programs, and some non-attainment areas have started enhanced inspection and maintenance programs. Malfunctioning distributed generators have the same potential to deliver disproportionate impacts.

Of course, an inspection and maintenance program that requires visits to people's basements on any sort of regular basis would be very expensive and cumbersome. The ideal solution will probably entail requiring a regular manufacturer service check-up combined with random inspections by state officials. States and particularly non-attainment areas could require that manufacturers include a service contract with each unit that includes biannual testing of the system's emissions and maintenance of all emissions control devices.

Advances in automated monitoring and telecommunications technology also allow remote monitoring of the operation and performance of emissions control equipment. Indeed, most currently installed fuel cells and microturbines are remotely monitored by their manufacturers. This type of solution could vastly decrease the expense of an inspection and maintenance program.

VII. Conclusion

Distributed generation technologies range from very clean to very dirty. They have the potential to play an important role in reducing air pollution and climate change, but they also have the potential to add significantly to urban smog and the concentration of greenhouse gases. Unless steps are taken now, the success of distributed generation will be its own worst enemy. By starting with certification labels and state-based mitigating measures and building into a comprehensive federal policy to control the emissions of distributed generation, this fledgling industry can grow into a vibrant part of a more sustainable future. ■

Endnotes:

1. See, for example, *Existing Emergency Power Can Avert Blackouts: Trigen CEO,* Dow Jones News Service, Aug. 2, 1999.

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2. U.S. DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION, ELECTRIC POWER ANNUAL 1998, Vol. I, Table 1.

3. Based on data from Energy Information Administration, *supra* note 2, EPA National Air Pollutant Emission Update 1990–1997, and emission values from this paper.

4. Northern Research & Engineering Corp.'s *NREC News*, Vol. 13, No. 1, fall 1999, at 7.

5. 40 Code of Federal Regulations Part 60, Subparts Da, Db, Dc, and GG.

6. 40 Code of Federal Regulations Part 70.

7. New York State Code of Regulations Part 201-3.

8. South Coast Air Quality Management District Rule Book, sections 1110.1, 1110.2, and others. Emissions rates were converted from ppm assuming a 40 percent efficient diesel engine. Interestingly, SCAQMD regulates engines and large turbines (Section 1134 and Rule 219) but currently does not cover turbines below 200 kW (i.e., microturbines).

9. EPA National Air Quality and Emissions Trends Report, 1997, Ch. 2.

10. U.S. DOE, ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK 2000, Table 1 at 7.

11. Twenty-three percent of new generation over the last five years has been from natural-gas combined-cycle turbines. This is up sharply from 8 percent in the five years before that and just 0.3 percent before that (Energy Information Administration, EIA Form 860 data file, www.eia.doe.gov/cneaf/electricity/page/eia860.html accessed, May 26, 2000). The near-60-percent efficiency of these devices promises to keep this number increasing for some time.

12. We recognize that this is a worst-case scenario. There will be specific cases where a distributed generator is being used to displace existing base load; in much of the country this means displacing coal generation. Furthermore, if distributed generators are operating as peakers, they could be displacing uncontrolled single-cycle turbines or even dirtier plants. A full analysis of what a given distributed generator will displace would require looking at the load cycle of the distributed generator and what is on the margin for each hour the generator will be running, and the local, state, and federal regulations controlling emissions in the region.

13. Of course, there is variation within this type of technology. In non-attainment areas, emissions will be closer to the lower end of the ranges. For instance, lowest achievable emission rate (LAER) standards in non-attainment areas would necessitate selective catalytic reduction (SCR) controls for NO_x emissions. In

other areas, combined cycle plants will not be as efficient or as clean. The EPA acid rain database indicates that average emission rates from existing combined cycle plants with SCR are about 0.20 lbs/MWh. Federal regulations ensure that for new plants, this range is bounded.

14. Indeed, biomass can have an effectively negative carbon impact if the source of fuel would have otherwise been converted into uncaptured methane. Generally, the analysis of biomass requires more attention to its life cycle impact than this article can allow. The impact on recycling, fertilizer usage, and soil erosion should all be considered.

15. For a long time, the electric industry was characterized by the increasing economies of scale of boilers and steam turbines. Larger power plants were more efficient and therefore cheaper to run. With the advent of the combustion turbine generator, this rule was broken. Suddenly, natural gas plants could be as small as a few tens of megawatts and be more efficient than a 1,000 MW coal plant. What's more, combustion turbines have a relatively flat efficiency curve, meaning that while larger combustion turbines are more efficient than small ones, the difference is not as dramatic as with steam turbines. However, the higher and flatter efficiency curve of combustion turbines drops off well above the 1 MW size limit that we have chosen for this discussion.

16. Distributed generation can reduce the cost of transmission and distribution. However, the vast majority of utilities are currently regulated in such a way that decreased sales translates into decreased cost. Therefore they are hostile to any form of distributed resource that reduces throughput. As part of encouraging mitigating measures, states should shift from price cap regulation to revenue caps.

17. New York State Energy Research and Development Authority, 200 kW Fuel Cell Monitoring and Evaluation Program (Final Report 97–3) 1997. Also note that in this instance MWh are being used as a measure of all energy—both heat and electrical—captured from the system.

18. See Woody Delp *et al.*, *Field Investigation of Duct System Performance in California Light Commercial Buildings,* ASHRAE Transactions 1998, Vol. 104, Part 2; and D. Jump, I. Walker, and M.P. Modera, *Field Measurements of Efficiency and Duct Retrofit Effectiveness in Residential Forced Air Distribution Systems,* Proceedings, American Council for an Energy-Efficient Economy, Summer Study, 1996.

19. The U.S. Department of Energy's Energy Star CHP challenge program provides an excellent basis for state programs designed to encourage CHP.

20. Manufacturers of Emission Controls Association, *Emission Control Technology for Stationary Internal Combustion Engines,* July 1997.

21. South Coast Air Quality Management District Rule Book, section 1121. Manufacturers can also opt out of the certification process by paying a fee which is used to buy NO_x reductions elsewhere in the SCAQMD.

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Request 9c.

Suppose that EKPC's existing fleet of generating units causes 10.00 units of environmental damage per delivered kWh. Would "environmentally sound generation technologies" include all technologies that cause 9.99 units or less of environmental damage per delivered kWh? Would "highly polluting generation technologies" include all technologies that cause 10.01 units or more of environmental damage per delivered kWh? Please explain your answers.

Response 9c.

As suggested in response 9b above, I would propose that in order to be given favorable rate treatment under the QF tariff, a given generating technology should outperform the EKPC average emissions/kWh by a substantial margin, for example, by being 30% or 40% lower. This would prevent a QF from being financially rewarded despite the fact that its operation would not provide any noticeable environmental benefit to the public.

Request 9d.

What is the legal basis for your proposed price discrimination among QF technologies? How is your proposal consistent with the Kentucky statutory requirement, cited by you at page 27, lines 21-22, that QF rates shall be "nondiscriminatory"?

Response 9d.

There are many examples from all over the United States of state legislatures and public utility commissions enacting preferential laws, orders and policies to promote the growth of certain technologies for environmental reasons. One relevant example is the net metering statute, KRS 278.465 to 278.468, enacted by the Kentucky General

Assembly in 2004. The advantageous net metering treatment was reserved for generation technologies that use solar energy.

Other states have established generous avoided cost numbers and correspondingly high payments to qualifying facilities (QFs) that use relatively nonpolluting generation technologies.

The web site, www.dsireusa.org, provides state-by-state information about a range of incentives, policies, tariffs, and statutes that states use to encourage energy efficiency and clean renewable energy generation. By way of illustration, a copy of a small subset of that information is provided in response to the PSC Staff's information request 15a. These pages describe incentives and policies enacted by Maryland, Missouri, North Carolina, Oregon, and New York. Many states encourage small-scale renewable energy generation by applying net metering terms to technologies such as photovoltaics, wind power, solar water heating, solar thermal electricity, biomass, anaerobic digestion of animal wastes on farms, landfill gas, small-scale hydroelectric power, and biomass.

In general, the idea that a state would enact favorable policies to encourage renewable energy sources has become well-established in this country.

The issue of "non-discrimination" can be looked at in two different ways. One could claim that the word "nondiscriminatory" means that the Commission may never take account of any differences in the environmental impacts caused by various generating technologies, and that all resource decisions must be made solely on the basis of the lowest electric rate per delivered kWh. This approach, however, ignores the fact that environmental pollution has real, measurable economic impacts on customers, the public, and the environment. To claim that the Commission may not legally consider the different environmental impacts caused by various technologies is to mandate, in effect, that a value of zero be assigned to these environmental impacts.

The phrase that immediately precedes the word "nondiscriminatory" in 807 KAR 5:054, Section (7) is "in the public interest." To require the Commission to ignore the environmental and economic impacts of pollution is to contradict the requirement to set rates that are in the public interest. I would conclude that the word nondiscriminatory" cannot mean that relative environmental impacts must be ignored.

The other way to think about the meaning of the word "nondiscriminatory" would be to work toward a set of rates that correspond to the degree that each generating technology protects and furthers the public interest. One would conclude that the best way to achieve nondiscrimination among competing technologies would be to take account of the "external" costs that each technology imposes on the general public. Highly-polluting technologies that impose large external costs on the public would receive proportionally lower rates than nonpolluting technologies such as solar energy, wind power, and improved energy efficiency. Please refer to the rates contained in my proposed tariff for qualifying facilities submitted in response to the PSC Staff's information request 15. These rates embody the principle of nondiscrimination because they provide low economic rewards to technologies that impose large external costs on society, and higher rewards to cleaner, less-polluting technologies.

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 10

RESPONSIBLE PERSON: Geoffrey M. Young

Request 10.

Please provide studies that present quantitative evidence in support of your statement, on page 38, lines 8-12, that the "economic benefits that accrue to the electrical system when small-scale, distributed generation is added to the grid… 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." The evidence should identify particular technologies and include detailed quantitative information on their operating characteristics, costs, and benefits. (Please note that your Attachment D includes no quantitative information, and that many of the 2007 benefits are duplicates or variants of one another; so Attachment D is not sufficient to verify the statement quoted above.)

Response 10.

The following 17 pages are copied from the text of the book, *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size*, pages 117-133. There should be sufficient quantitative information in these pages about the costs, operating characteristics, and benefits of large-scale and small-scale resources to enable the reader to evaluate whether at least some of the conclusions listed in Attachment D are plausible. I highly recommend the book to utility planning personnel and regulators interested in minimizing the long-term total costs of providing energy services.

lead time, and will be even greater to the extent that large resources also take longer to build.

Chapman and Ward (115) correctly note that power planning takes place within "three separate planning horizons and processes"[9] that are "interdependent but separable, in the sense that they be considered one at a time in an iterative process, with earlier analysis in one informing the others." These three timescales, conceptually somewhat related to the scales of fluctuation described in Section 2.2.1 above, could be restated as:

- the short-term *operational* scale of keeping the grid stable, supply and deliverability robust, and the lights on, ranging from real-time dispatch to annual maintenance scheduling;
- the medium-term *planning* scale of keeping supply and demand in balance over the years through a flexible strategy of resource acquisition, conversion, movement, trading, renovation, and retirement; and
- the long-term *visionary* scale of ensuring over decades that the mix, scale, and management of energy systems are avoiding fundamental strategic errors; opening new options through farsighted RD&D and education; fostering a healthy evolutionary direction for institutional, market, and cultural structures, patterns, and rules; and sustaining foresight capabilities that will support graceful adaptation to and leadership in the unfolding future.

All three timescales are vital. So is not mixing them up. And so is seeking opportunities to serve synergistically the goals of more than one at a time, rather than creating tradeoffs between them. We therefore turn now to ways to value some specific attributes—modularity, modest scale, and short lead planning and installation times—of distributed resources that also happen to offer advantages on all three timescales and levels of responsibility.

2.2.2 Valuing modularity and short lead times

To reduce the financial risks of long-lead-time centralized resources, it is logistically feasible (§ 1.5.7) to add modular, short-lead-time distributed resources that add up to significant new capacity. But can those smaller resources create important economic benefits by virtue of being faster to plan and build? Common sense says yes, and suggests three main kinds of benefits: reducing the *forecasting risk* caused by the unavoidable uncertainty of future demand; reducing the *financial risk* caused directly by larger installations' longer construction periods; and reducing the *risk of technological or regulatory obsolescence*. Let us consider these in turn.

2.2.2.1 Forecasting risk

Nearly twenty years ago, M.F. Cantley noted that "The greater time lags required in planning [and building] giant power plants mean that forecasts [of demand for them] have to be made further ahead, with correspondingly greater uncertainty; therefore the level of spare capacity to be installed to achieve a specified level of security of supply must also increase." (90) Longer lead time actually incurs a double penalty: it increases the uncertainty of demand forecasts by having to look further ahead, *and* it increases the penalty per unit of uncertainty

[9] They add that "Additional (four or more) horizons might be usefully explored, but fewer than three will cause difficulties."

Benefits

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.*

by making potential forecasting errors larger and more consequential. As *Business Week* put it in 1980 , "Utilities are becoming wary of projects with long lead times; by the time the plant is finished, demand could be much lower than expected. If you're wrong with a big one, you're really wrong.... Uncertainty over demand is the main reason for the appeal of small plants."

This forecasting risk became painfully evident in the 1970s, when the power industry consistently overestimated demand growth while lead times for large new generating plants became longer and more uncertain, the cost of capital soared, and utilities used planning models "biased toward large plants." The interaction of these four factors created "an increased likelihood of excess capacity, unrecoverable costs and investment risk" that bankrupted a few utilities and severely strained scores more. The industry therefore learned the hard way that minimizing risk "will tend to favor smaller scale projects, with shorter lead times and less exposure to economic and financial risks." Specifically :

- An autumn 1978 *Energy Daily* review of data collected by the Edison Electric Institute in autumn 1978 showed that only once in the previous 11 years had the industry underpredicted the following year's total noncoincident peak demand, and then only by 0.1 percentage point. Rather, the forecasts averaged 2.1 percentage points too high during 1968–73 and 5.1 percentage points too high after 1974. Indeed, during 1974–79, the average forecast error exceeded the average annual growth rate, and during 1975–78 the error averaged 2.5 times the actual growth—leading the editor of *Electrical World* to call for a major rethinking of traditional forecasting methods (289) (see Figure 1-41 in Part One).

- In such an uncertain forecasting environment, "The alternative to waiting 12 years to see whether demand growth did justify construction of an expensive large generator...is building smaller projects with shorter lead times." (522) For example, if a utility forecast 5.5% annual demand growth, built new generators with 12-year lead times, and actually experienced only 3.5% annual demand growth, then it would end up with 26% excess capacity. If the lead time were 6 years, however, that excess would drop to 12%; if 4 years, to 8%.
- Lead time correlated well with unit size: *e.g.*, for U.S. coal-fired plants in the 300–700-MWe range, each 100 MW of capacity required an extra year of construction. Although different analysts' values for this coefficient vary,[10] the existence of an important bigger-hence-slower correlation has long been well established (12, 557).

For these reasons, as summarized by Sutherland *et al.* (673), with emphasis added,

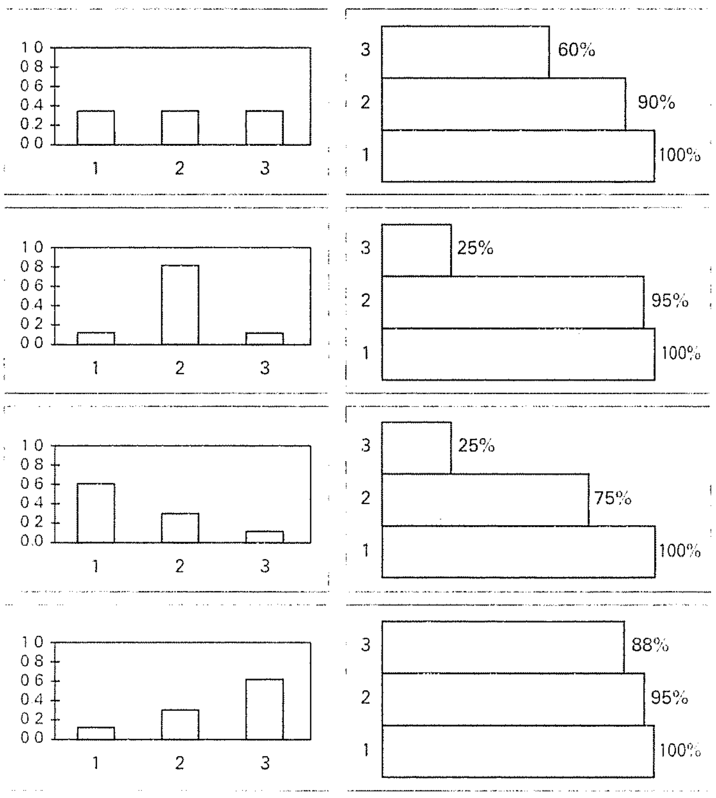
> The most important result is that short lead time technologies, which represent smaller units, are a defense against the serious consequences of unforeseen changes in demand. The "worst case" occurs when electric utilities build large and long lead time plants [but]...anticipated demand is unrealized. A price penalty is paid by consumers, and unfavorable financial conditions plague the utility. Ford and Yabroff (1980, 78) concluded that the strategy of building small, short lead time plants could cut the price penalty to the consumer by 70% to 75%. *Both demand uncertainty and short lead times favor small generating units, with their synergistic effects being the most important.*

The mechanisms of that synergy become more visible when one looks more closely into the details of demand uncertainty. A lucid analysis of the tradeoffs between hoped-for power-plant economies of scale and the risk of excess capacity (75) (Figure 2-2) provides cost ratios showing how much cheaper the output from a larger unit must be, if it takes twice as long to build as a small plant, in order to justify buying the large plant under a given pattern of demand uncertainty. That pattern is expressed as the probability that during the planning period, demand will grow by one, two, or three arbitrary units, which can be interpreted as relative percentage growth rates. Those probabilities can occur in various combinations. For each, a set of ratios shows how much cheaper the large plant must be than the small plant in order to justify building the large one. In general, the assumed demand growth will justify at least one large unit. But to justify a second or third large unit, it must be modestly or dramatically cheaper than the smaller units, depending on the distribution of demand probabilities. The left-hand graph in each case shows the assumed distribution of probabilities (for example, in the first case, all three demand growth rates—*e.g.*, *x*, 2*x*, and 3*x*—are equally probable). The right-hand graph shows in the first case,

[10] For example (673), a RAND multiple-regression analysis by William Mooz found a correlation equivalent to ~3 5 months of construction duration per 100 MWe of net capacity (but actually a bit nonlinear), while a comparable analysis in a different algebraic form, by Charles Komanoff, found that a doubling of nuclear unit size would increase construction time by 28% (Komanoff's capital-cost model for coal plants didn't use unit size as a variable, but unit size was the variable most significant in affecting construction duration) A further analysis cited (673), using an EPRI database of 54 coal and nuclear plants, didn't examine unit size as an explanatory variable, but did find that 22% of the nuclear units' construction delay was deliberate in an effort not to build too far ahead of demand, implying that "the utility would have been better off with smaller and shorter lead time plants "

for instance, that a large unit is justifiable at full cost as the first unit to be built, but must be 10% cheaper than the small plant to be the right choice as the second unit, and 40% cheaper as the third unit.

Figure 2-2: Uncertain demand imposes stringent cost tests on slow-to-build resources
Long-lead-time power stations must be far cheaper than halved-lead-time smaller units in order to be an economical way to keep on meeting changing demand (unless, perhaps, demand growth is known to be accelerating).



Source: E. P. Kahn, "Project Lead Times and Demand Uncertainty: Implications for Financial Risk of Electric Utilities" (Lawrence Berkeley Laboratory/University of California, 1979), p. 9, fig. 4

Thus continuing to build large plants requires them to be built at an increasingly steep cost discount even if demand growth is steady (the first case); is unlikely to be the right strategy if demand fluctuates markedly (the second case) or demand growth tapers off (the third case); and may be justifiable if demand growth is definitely and unalterably accelerating (the fourth case). This comparison—focusing only on a specific kind of investment risk, and not taking account of several dozen other effects of scale on economics—is of course a simplified illustration of planning choices that could be simulated more elaborately, typically by a Monte Carlo computer analysis. But simple though it is, the example starkly illustrates the risks of overreliance on long-lead-time plants when demand is uncertain: in the middle two cases, the third large unit could be justified only if it were *fourfold cheaper* than the competing small, halved-lead-time unit. The authors conclude:

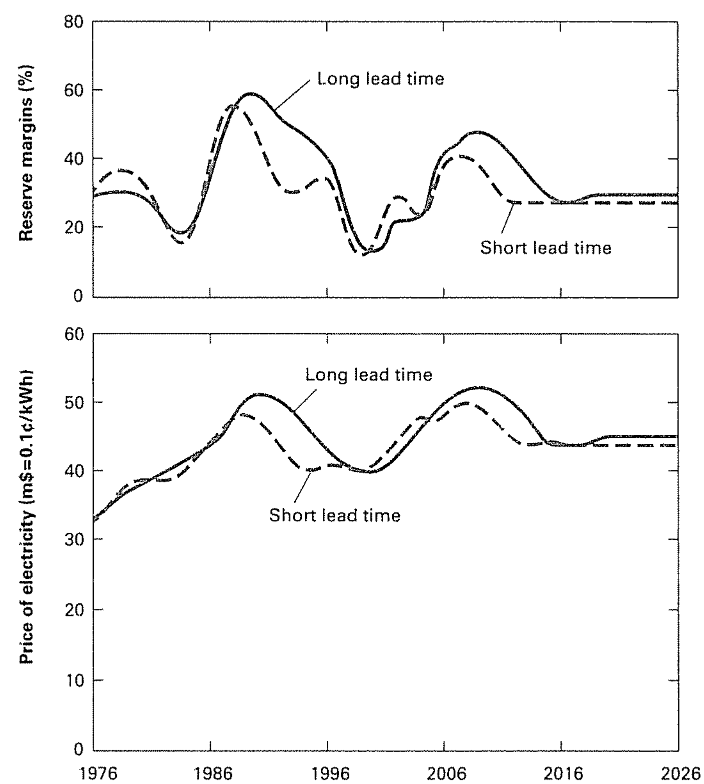
> The relative cost advantage of short lead time plants can be substantial. If demand uncertainty is such that low growth rates of demand are more likely than high growth rates, or if the variance in demand growth is simply large, the capital cost of long lead time plants must be substantially decreased, under some circumstances as much as 50%[,] to make long lead time plants cheaper, even with a flat load curve. The fraction of future demand that is optimally satisfied with long lead time power plants depends on two factors. Again, the lower the probability that a given level of demand will occur, the greater the cost advantage required to make long lead time plants optimal for that level. This conclusion is modified by the existing mix of short lead time—high [fuel] cost plants and long lead time—low fuel cost plants. The more short lead time plants in the existing mix[,] the smaller the cost advantage of long lead time plants needs to be. In general[,] unless long lead time plants have a substantial cost advantage or the probability of the demand['s] growing at the maximum rate is large, it is rarely optimal to supply all the projected demand with long lead time plants.

In summary: if too many large, long-lead-time units are built, they are likely to overshoot demand. Paying for that idle capacity will then raise electricity prices, further dampening demand growth or even absolute levels of demand, and increasing pressure for even further price increases to cover the revenue shortfall. This way lies financial crisis, as the industry found to its cost in the 1970s and 1980s.

Of course, forecasting errors go both ways: you can build capacity that you turn out not to need, or you can fail to build a plant that you *do* turn out to need. Are those risks symmetrical? In the 1970s, when power-plant (especially nuclear) vendors were trying to justify their seemingly risky GW-range products, they cited studies purporting to show that underbuilding incurred a greater financial penalty than overbuilding (100, 671). However, those studies' recommendation—to overbuild big thermal plants as a sort of "insurance" against uncertain demand—turned out to result from artifactual flaws in their models (243, 249, 417).[11] More sophisticated simulations, on the contrary, showed that (at least for utilities that don't start charging customers for power plants until they're all built and put into service) if demand is uncertain, financial risk will be minimized by deliberately *under*building large, long-lead-time plants (75, 243–4, 246–7, 249).

For example, given an illustratively irregular pattern of demand growth characteristic of normal fluctuations in weather and business conditions, excessive reserve margins and electricity prices can be reduced by preferring short-lead-time plants (Figure 2-3):

Figure 2-3: Faster-to-build resources help avoid capacity and price overshoot
Short-lead-time plants help to avoid excessive reserve margins and tariffs under uncertain demand.



Source: A. Ford and A. Youngblood, "Simulating the Planning Advantages of Shorter Lead Time Generating Technologies" (*Energy Systems and Policy* 6, 1982), p. 360, figs. 7 and 8

[11] The EPRI models assumed that all forms of generating capacity are expanded at the same rate, so that baseload shortages automatically incur [large] outage costs rather than extending the capacity or load factor of peaking or intermediate-load-factor plants. (This assumption means that the plant-mix questions at issue simply cannot be examined, because plants are treated as homogeneous.) Furthermore, the use of planning reserve margin as the key independent variable obscured the choice between plants of differing lead times. Capital costs were assumed to be low, so that even huge overcapacity didn't greatly increase fixed costs. Outage costs were treated as homogeneous, even though it would make more sense to market interruptible power to users with low outage costs. Uncertainties were assumed to be symmetrical with respect to under- or overprediction. And the opportunity costs of over- or underbuilding were ignored, whereas in fact, overbuilding ties up capital and hence foregoes the opportunity to invest in end-use efficiency or alternative supplies, while underbuilding means one still has the capital and can invest it in ways that will hedge the risk. For further comparative discussion of conflicting studies, see (249).

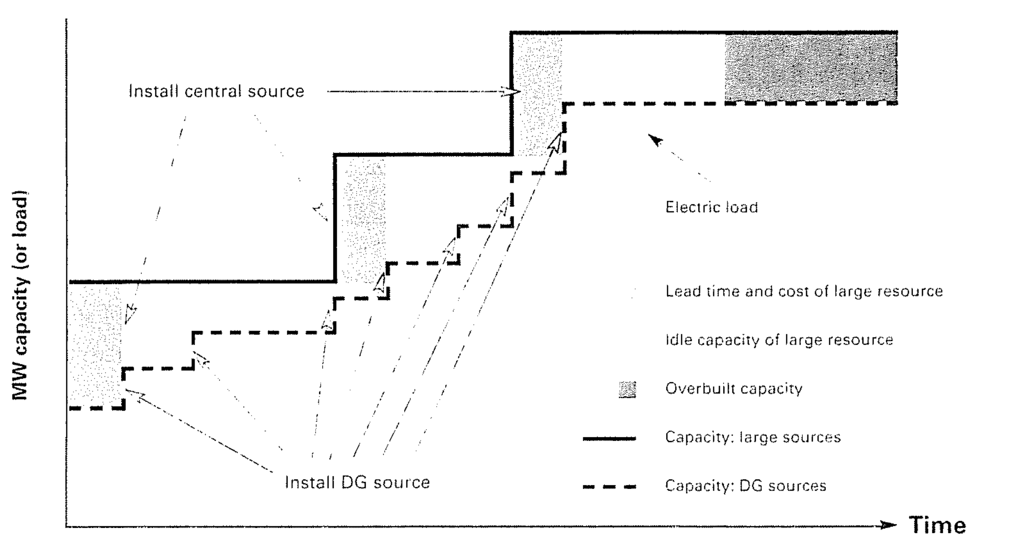
There are four reasons for this:

- operating short-lead-time, lower-thermal-efficiency, low-capital-cost stopgap plants (such as combustion turbines fueled with petroleum distillate or natural gas) more than expected, and paying their fuel-cost penalty, is cheaper than paying the carrying charges on giant, high-capital-cost power plants that are standing idle;[12]
- even if this means having to build new short-lead-time power stations such as combustion turbines, their shorter forecasting horizon greatly increases the certainty that they'll actually be needed, reducing the investment's "dry-hole" risk;
- smaller, faster modules will strain a utility's financial capacity far less (for example, adding one more unit to 100 similar small ones, rather than to two similar big ones, causes an incremental capitalization burden of 1%, not 33%); and
- short-lead-time plants can be built modularly in smaller blocks , matching need more exactly.

This last point is so obvious that it is often overlooked: big, "lumpy" capacity additions *invariably* overshoot demand (absent gross underforecasting of rapidly growing demand), leaving substantial amounts of the newly added capacity idle until demand can "grow into it" (Figure 2-4).[13]

Thus adding smaller modules saves three different kinds of costs: the increased lead time (and possibly increased total cost) of central resources; the cost of idle capacity that exceeds actual load; and overbuilt capacity that remains idle. Both curves maintain sufficient capacity to serve the erratically growing load, but the small-module strategy does so more exactly in both

Figure 2-4: Slow, lumpy capacity overshoots demand in three ways
The yellow areas show the extra capacity that big, lumpy units require to be installed before they can be used. Small distributed-generation (DG) modules don't overshoot much; they can be added more closely in step with demand. The blue areas show the extra construction and financing time required by the longer-lead-time central units.



Source: J. N. Swisher, "Cleaner Energy, Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources" (RMI, 2002), www.rmi.org/sitepages/pid171.php

Naturally, this sort of conclusion is not immutable, but rather depends on interest rates, fuel costs, and other factors that change over time.

This is quite an old and familiar problem in mathematical economics. The latter paper concludes that "efficient production when there is uncertainty of demand forces the supplier to sacrifice economies of [unit] scale in order to achieve greater flexibility through a larger number of plants. Equally important is the result that full efficiency requires a set of plants of different sizes. Thus there is no optimal scale of plant or minimum efficient scale and in fact such a concept is meaningless in the present context. Only the collection of all plants is efficient."

quantity and timing, and hence incurs far lower cost.

This load-tracking ability has value unless demand growth not only is known in advance with complete certainty, but also occurs in step-functions exactly matching large capacity increments. If that is not the case—if the growth graph is diagonal rather than in vertical steps, even if it is completely smooth—then smaller, more modular capacity will tie up less idle capital for a shorter period.

If demand grows steadily, the value of avoiding lumps of temporarily unused capacity can be estimated by a simplified method modified by Hoff, Wenger, and Farmer (324) from a 1989 proposal by Ren Orans. The extra value of full capacity utilization is proportional to:

$$\frac{T(d-c)}{1-e^{-T(d-c)}}$$

where d is the [positive] real discount rate, c is the real rate at which capacity cost escalates, and T is years between investments. This approximation yielded reasonable agreement with PG&E's estimate (§ 2.3.2.6) for deferring Kerman transformer upgrades (324).

This analysis also provides a closed-form analytic solution for the case where the distributed resource is becoming cheaper with time, so even if it's not cost-effective now, it is expected to become so shortly. If the relative rates of cost change between the distributed and traditional resources are known, due allowance can be made. The equations provided (324) can also use option theory (§ 2.2.2.5) to account for uncertainties in the cost of the distributed resource. Such uncertainty may create additional advantage by suitably structuring the option so that the manager is entitled but not obliged to buy, depending on price. For these reasons, in an actual situation examined, a distributed resource costing $5,000/kW can be a cost-effective way to displace generating investments that would otherwise be made annually, plus transmission investments that would otherwise be made every 30 years—largely because the lumpiness of the latter investment means paying for much capacity that will stand idle for many years.[14]

In any actual planning situation, depending on the fluctuating pattern of demand growth, the extra cost of carrying the lumpy idle capacity can be calculated from the detailed assumptions, and then interpreted as a financial risk. Some tools for this calculation are described below. In principle, but not in most models, such a calculation should take into account an important economic feedback loop—the likelihood that the higher electricity tariffs needed to pay that extra cost will make demand growth both less buoyant and less certain, further heightening the financial risks (247–8). This sort of feedback is probably best captured by system dynamics models (248). Those models broadly confirm the "death spiral" scenario characteristic of plants that take longer to build than it takes customers to respond to early price signals from the costly construction—especially if demand is as sensitive to price as many econometric analyses suggest.[15] Avoiding the risk of the "death spiral" is an important potential benefit.

[14] It's important for the analytic tools used in this situation to capture declining costs incrementally and immediately, so that no cost reduction is delayed or lost through stepwise capture at longer intervals.

[15] Econometric studies collected by Ford and Youngblood (248) found long-run own-price elasticities of demand as large as –1.5 in the residential and commercial sectors and –2.5 in the industrial sector, with widely varying time constants. In general, elasticities with an absolute value larger than unity can lead to trouble; many of the values cited, including most of the industrial ones, are in this range. (An elasticity of –1.5 means that each 1% increase in price leads to a 1.5% decrease in demand. "Own-price" refers to the price of the same commodity whose demand is being measured, that differs from "cross-price" elasticities, which describe substitution of one resource for another as their relative prices change. "Long-run" typically refers to a period of years.)

Benefits

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.*

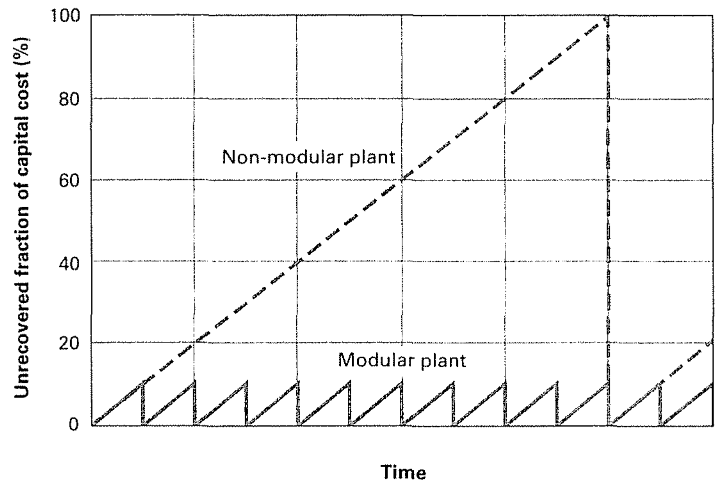
2.2.2.2 Financial risk

For all the reasons described in Section 2.2.2.1, shorter lead time and smaller, more modular capacity additions can reduce the builder's financial risk and hence market cost of capital (371, 417–8). But there are even more causes for the same conclusion (675):

1. Shorter lead time means less accumulation of AFUDC, a lower absolute and fractional burden of interest payments during construction (140), higher-quality earnings that reflect more cash and less fictitious "regulatory IOU" book income, and lower cost escalation during the construction interval (384, 493). One manifestation of these effects is that with highly modular projects, the developer "only needs enough working capital to finance one segment at a time. Once the first segment is completed, the unit can be fully financed, and the proceeds used to finance the next segment" (Figure 2-5).

This is analogous (317) to building houses that are sold as they're completed, rather than tying up much more capital in an apartment building that can't yield any rental revenue until it's all finished.

Figure 2-5: Modular plants reduce need for working capital
Modular plants can need 10+ times less working capital than lumpy plants, reducing default risk and perhaps therefore the modular units' cost of capital.



Source: T E Hoff and C Herig, *The Virtual Utility: Accounting, Technology and Competitive Aspects of Emerging Industry* (Kluwer Academic Press, 1997), p 26, fig 9

Allowance for Funds Used During Construction (AFUDC) is a U.S. utility accounting practice virtually unknown in most countries and baffling to non-utility businesspeople. Especially during the nuclear construction boom of the 1970s, many state utility commissions issued a sort of "regulatory IOU" by permitting utilities to reflect on their books a fictitious, noncash income item representing the *cost* of capital (both debt and equity) tied up in the construction project but not yet ready to generate electricity and hence to earn revenue. The principle was that the utility's financial reports would then look as healthy (superficially) as they would actually become when the project was completed, electricity flowed to customers, and real revenues were earned. Unfortunately, some utilities became so dependent on this unreal revenue that it came to provide a substantial fraction of their book income. If the project were then abandoned, as sometimes occurred, then the gap between reported and actual cash income would become painfully apparent. The alternative regulatory treatment—including **CWIP (Construction Work in Progress)** in the commission-approved **rate base** of assets on which utilities were authorized to earn a return on and of capital—allowed the utilities to start charging customers for money spent on projects not yet completed. This method defied the normal principle that ratebased assets must be "used and useful," and it had:

- the economic advantage of providing a more nearly correct marginal price signal early enough that customers could value the electricity more appropriately and presumably use it more judiciously—possibly making the plant largely or wholly unnecessary;
- the economic disadvantage that this price signal did no good because the utility had no intention of canceling the project even if demand growth slackened or reversed;
- the political advantage of placating the utility and its investors; and
- the political disadvantage of infuriating customers who were having to pay for an asset that was doing them no good and might never operate at all.

The resulting regulatory and legal wars are now history, and the wholesale competition begun in 1992 has largely transformed the structure that created them, but even a few decades later, their scars persist on some utilities' financial and political balance sheets.

2. Shorter lead time means that the utility does not have to keep as much capacity under construction, costing money and increasing financial risk, to meet expected load growth in a timely fashion.

3. Shorter lead time means that units get into the rate base[16] earlier, or, in the case of a privately owned plant, can start earning revenue earlier—as soon as each module is built rather than waiting for the entire total capacity to be completed. This benefit has been quantified (317), with an example of a 500-MW plant built in one segment over five years *vs.* ten 50-MW modules with 6-month lead times (Figure 2-6). If each asset runs for 20 years, then under either plan, the same capacity operates identically for the middle 15 years—but the modular plant has higher revenue-earning capacity in the first five years, and conversely in the last five years as the modular units retire. But because of discounting, the early operation is worth much more today. Using a 10%/y discount rate and \$200/MWy revenues, the modular solution will have an astonishing 31% higher present-valued revenue. If the modular plant were infinitely divisible and had zero lead time, then regardless of the life of the plant, the ratio of present-valued revenues would be $(e^{Ld} - 1)/Ld$, where L is the number of years it takes to complete the nonmodular plant and d is the annual real discount rate (317).

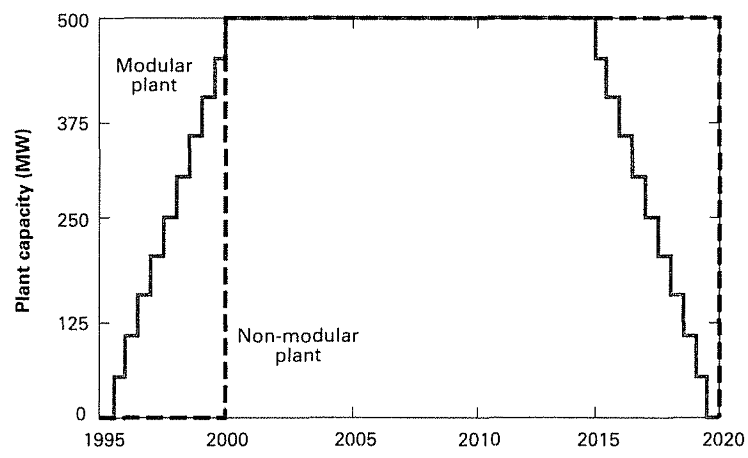
4. Short lead time allows the companies a longer "breathing spell" after the eventual startup of the large units that are currently under construction (so that they can better recover from the financial strain of those very costly and prolonged projects). This is analogous to a mother's stretching out the spacing of her bearing children.

5. These four advantages allow the company to avoid poor financial performance. Thus, the short-lead-time unit allows the company to avoid the increase in financing costs that can occur when a firm misses its financial goals.

These conclusions are also reinforced by four other factors that affect financial cost and risk, notably:

6. Shorter lead time decreases the burden on utility cashflow as expressed by such indicators as self-financing ratio, debt/equity ratio, and interest coverage

Figure 2-6: Modular resources' early operation increases their present value
Modular plants can start yielding revenue while big, slow, lumpy plants are still under construction.



Source: T E Hoff and C Herig. *The Virtual Utility. Accounting, Technology and Competitive Aspects of Emerging Industry* (1997), p 22, fig 7

[16] Under traditional U S (and most other) rate-of-return regulation, utilities are entitled to charge customers approved tariffs expected to yield "revenue requirements" that consist of two kinds of prudently incurred costs. operating expenses, and a fair and reasonable return on and of capital employed to provide "used and useful" assets The "rate base" on which the utility has the opportunity to earn that regulated return is thus the sum of those used and useful assets Therefore, the sooner a power station enters service, the sooner it starts earning returns

ratios—all used by financial analysts to assess risk for such purposes as bond ratings and equity buy/sell recommendations (375, 757).

7. Shorter lead time may decrease the incentive, and the bargaining power, of some workers or unions. Otherwise their indispensable skills may give them the leverage to demand extremely high wages or to stretch out construction still further, as occurred on the Trans-Alaska Pipeline System and many of the later U.S. nuclear power plants.

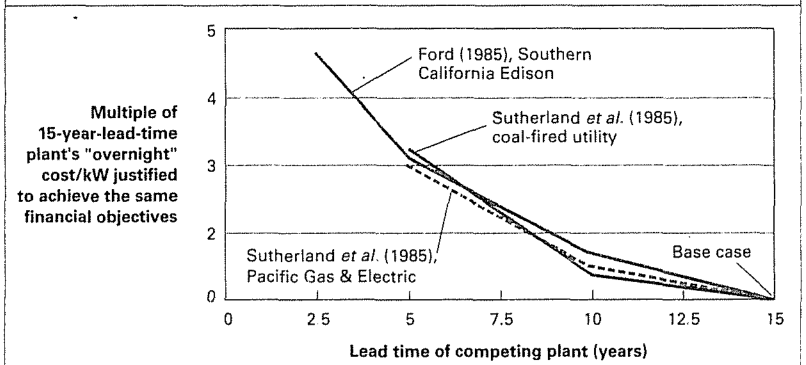
8. Smaller plants may have less obtrusive siting impacts (250). This can avoid the vicious circle, pointed out by H.R. Holt, in which utilities seeking to minimize siting hassles may maximize capacity per site, making the project so big and problematical that the plant is perceived as a worse neighbor, hence increasing political resistance to such projects and making the next site that much harder and slower to find, and so on.

9. Shorter lead time reduces the risk of building an asset that is already obsolete—a point important enough to merit extended discussion in the next section.

The first five of these benefits emerged strikingly from a Los Alamos National Laboratory system dynamics study in 1985 (677). The analysts used a Northern California case study for Pacific Gas and Electric Company under the regulatory policies prevailing in the early 1980s. They examined how both the "lead time" to plan, license, and build a generic power station and the financial or accounting cost of that lead time (due to real cost escalation and interest on tied-up capital) would affect its economic value over a 20-year planning horizon. However, to clarify choices, they inverted the calculation: Rather than modeling longer-lead-time plants as riskier or costlier (in present-valued revenue requirements), they simulated the utility's financial behavior and asked how much "overnight" (zero-lead-time) construction cost could be paid for the plant as a function of its actual lead time in order to achieve the same financial objectives.

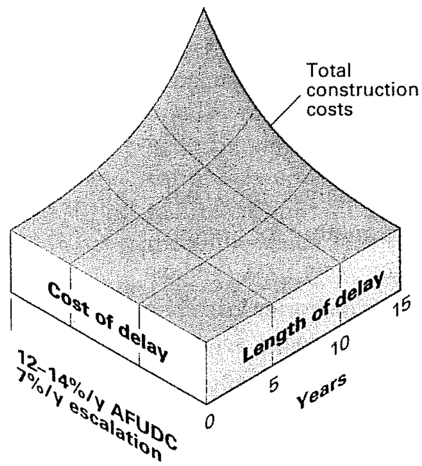
Adding also a similar analysis for a coal-fired utility (677) and another for Southern California Edison Company (245), the Los Alamos team found that shorter lead times justified paying about one-third to two-thirds more per kW for a plant with a 10- instead of a 15-year lead time; that a 5-year lead time would justify paying about *three times* as much per kW; and that a 2.5-year lead time (analyzed only for SCE) would justify paying *nearly five times* as much per kW. In each case, these far costlier but shorter-lead-time plants would achieve exactly the same financial performance as their 15-year-lead-time competitors under the same exogenous uncertainties, for the first five reasons listed above. Shown all on the same graph, the results look like this:

Figure 2-7: Power-plant financial feasibility *vs.* lead time
To achieve the same financial performance and risk, power plants with severalfold shorter lead time can compete even at severalfold higher construction costs.



Source: W. R. Meade and D. F. Teitelbaum, "A Guide to Renewable Energy and Least Cost Planning" (Interstate Solar Coordination Council, 1989), p. 11, ex. 8; R. J. Sutherland *et al.*, "The Future Market for Electric Generating Capacity: Technical Documentation" (Los Alamos National Laboratory, 1985), pp. 145–146

Figure 2-8: Slow construction multiplies its costs
Construction costs spiral with the combination of lead times, interest rates, and cost escalation rates.



Source: R J Sutherland *et al*. "The Future Market for Electric Generating Capacity: Technical Documentation" (Los Alamos National Laboratory, 1985), p 114

These findings clearly show that the longer or costlier the actual lead time, the greater its cost, and hence the costlier the short-lead-time plant that could compete with it:

However, that analysis (678) is conservative—it *understates* the benefits of short lead time—because it

> ...assumes a surprise-free, predictable future. There are no unexpected changes in regional economic growth, fuel prices, lead times, or [competing private generation] activity that might lead to adverse ratepayer or stockholder impacts when implementing the...resource plan. Thus, the fourfold cost advantage identified for short lead time plants...does *not* depend on the flexibility that shorter lead time plants offer in the face of uncertainty.

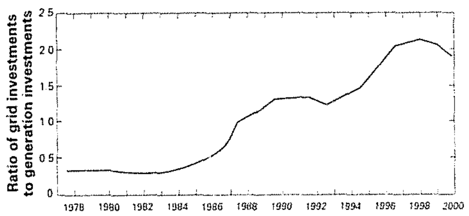
Sensitivity tests of the effect of a surprise (a ±100% change in demand growth rate halfway through), under a variety of other assumptions, confirmed that in most cases, short-lead-time plants would substantially increase the benefits or reduce the penalties of surprises, further increasing the value of short lead times (674).

These Los Alamos simulations show that plants with a 3–4-fold shorter lead time can cost (in "overnight" $/kW terms) about three times as much per kW, yet still yield the same—or, taking account of resilience under surprises, better—financial performance. Yet most distributed resources have lead times considerably shorter than the smallest value analyzed, 2.5 years; some take more like 2.5 months, weeks, or days to install. As construction time converges toward the theoretical "overnight" ideal, wouldn't distributed resources earn an even *larger* tolerance of higher overnight cost? Moreover, wouldn't similar considerations apply not just to generating but also to *grid* investments? If so, mightn't it be worth even more to avoid grid investments, since

- U.S. utilities have lately been investing more than twice as much on grid as on generating assets. As recently as 1978, during the nuclear boom, U.S. utilities invested only one-third as much in the grid as in generating capacity. However, as Figure 2-9 shows, since the mid-1980s, investments in the grid have become dominant, even before much new generating capacity began to be financed and owned by non-utilities;
- emerging pure-distribution companies have almost no investments *but* the grid; and
- it is even more difficult to forecast demand accurately for a small area (which has less load diversity and is more subject to the vagaries of individual large customers, sectors, or neighborhoods) than for a whole utility system (which tends to average out random differences between customers, sectors, or regions)?

Until 1997, no answer to these questions had been published. But in that year, energy economist and systems analyst Thomas Hoff

Figure 2-9: Utility investments are now dominated by the grid
U.S. investor-owned utilities are now devoting more than twice as much capital expenditure to the grid as to generation.

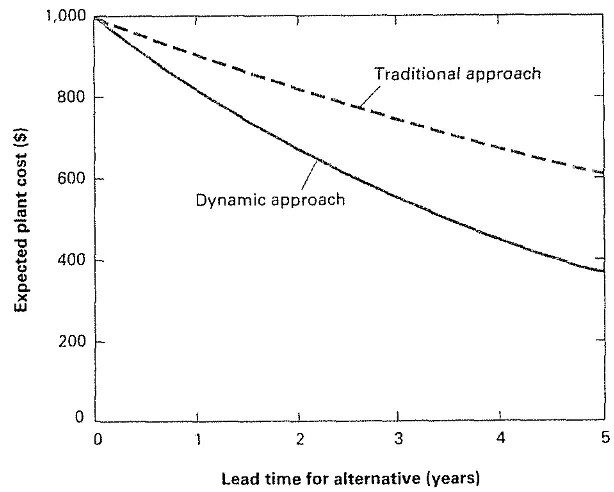


Source: EEI (Edison Electric Institute), *Statistical Review of the Electric Power Industry 2001* (EEI, 2002)

released a closed-form analytic solution (315) for the simplified case where demand growth fluctuates according to stochastic binary steps, in much the way others analyzed using decision theory (§ 2.2.2.6). This can make distributed resources cheaper than lumpy grid upgrades or generation expansions—the opposite of the conclusion reached when demand is viewed statically (via low, medium, and high growth scenarios) rather than dynamically as an unfolding process. For example, because the longer the lead time, the greater the demand uncertainty, if in any year there is a 50% probability that demand will increase (assumed to occur at a rate that uses up system reserve margin in one year), then at a 10%/y real discount rate, a $1,000 plant has a lower expected value—the longer its lead time, the less valuable it becomes. That is especially true if demand growth is considered as a dynamic process (Figure 2-10) based on those assumptions. The message of the graph—more fully explained by Hoff (315)—is that the dynamic unfolding of demand over time increases the risk reduction offered by short-lead-time plants; and the longer the difference of lead time (or the smaller the probability of rapid demand growth), the more dramatic this value advantage becomes.

Hoff's analytic approach (315) is illustratively applied to a system with equal probability of 0- or 5-MW demand growth each year; five years' worth of grid capacity remaining before the maximum rate (5 MW/y) of demand growth would require either expansion or distributed-resource reinforcement; and a 10%/y discount rate. Grid expansion is assumed to cost $25 million ($500/kW) and have a 5-year lead time, while distributed PV capacity would come with 1-year lead time and in 5-MW increments, each costing $15 million but returning $5 million in system benefits for a net per-unit cost of $2,000/kW. Thus ten increments of PV expansion would provide the same total capacity as the single 50-MW lump of grid upgrade. On these assumptions, *the expected present-valued cost is lower ($24 million) for the PV than for the grid-expansion ($25 million) choice, even though per kW the PV choice is four times as costly.*

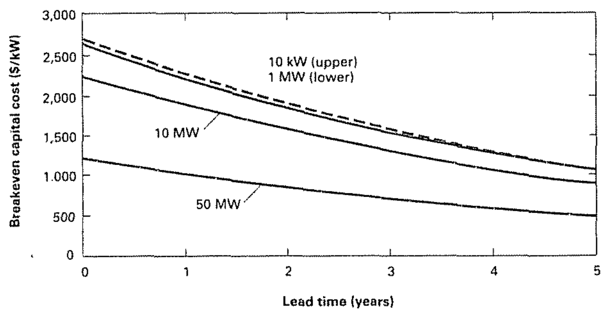
Figure 2-10: Counting the dynamic nature of demand growth increases the value of short-lead-time plants
Considering demand growth as a dynamically unfolding process makes longer-lead-time plants even less valuable because so much more uncertainty accumulates about whether and when they might be needed.



Source: T E Hoff, *Integrating Renewable Energy Technologies in the Electric Supply Industry A Risk Management Approach* (NREL, March 1997), p. 39, fig 5-5 www.clean-power.com/research/riskmanagement/iret pdf

Thus "highly modular, short lead time technologies can have a much higher per unit cost than the non-modular, long lead time T&D upgrade and still be cost-effective." The analytic solution shows the following variation of breakeven PV net cost with both module size and lead time, based on the grid-displacement benefits flowing from the assumptions in the previous paragraph:

Figure 2-11: Smaller, faster grid-support investments are worth more
For a typical grid-reinforcement application, smaller and faster distributed-resource modules can compete with a lumpy grid expansion even if they cost manyfold more per kW. Please see text for assumptions.



Source: RMI analysis from Eq. 5.6 in T. E. Hoff, "Using Distributed Resources to Manage Risks Caused by Demand Uncertainty" (PEG, 1997)

Thus Hoff shows that the value of short lead time, shown by the Los Alamos studies for generating plants down to 2.5-year lead times, *also continues all the way down to zero lead time*, and is equally valid for analogous grid applications. Moreover, Hoff quantifies the additional value of small modules that better respond to fluctuating demand growth. (That value can also be assessed using option or decision theory, as discussed below in Section 2.2.2.5 and Section 2.2.2.6 respectively.) The analytic solution is (311):

$$E = I\left\{1+\left(\frac{p}{d}\right)\left[1-\frac{1}{\left(1+\frac{d}{p}\right)^{N-1}}\right]\right\}\left(\frac{1}{1+\frac{d}{p}}\right)^{T-L}$$

where

E = expected present-value cost

I = total investment cost of all plant increments

L = lead time (in years) of units, which are assumed to differ only in this respect and in cost, not in capacity

p = probability that demand will increase at a given step

d = real discount rate (in decimal format, per year)

T = number of years before demand growth at the highest possible rate (by growing at all possible steps) will use up available capacity (assuming $T>L$)

N = number of units needed to achieve desired increase in capacity

The term before the multiplication sign expresses the benefit of modularity; the second term shows the benefit of short lead time. Of course, as noted earlier, these two values are especially powerful in combination. That will occur when smaller modules *also* have shorter lead time, so that these two attributes are associated rather than unrelated. This will frequently occur in practice.

Moreover, Hoff's graphed results for the illustrative assumptions listed above (Figure 2-11) assume that the distributed resource has a real price that doesn't change over time. But in fact, PV prices have been declining at about 9%/y (311). If that continues, then "PV could have a current price of more than $6,000/kW [excluding non-grid benefits such as generating capacity, energy, energy loss savings, externalities, etc.] and still be a lower cost alternative than the T&D upgrade. This is because [if the grid upgrade takes five years but the PV installation only one year] there will be no investment in PV for at least four years (when its cost will be reduced to about $4,000/kW)." (311)

In fact, the Sacramento Municipal Utility District's turnkey bid price for complete residential PV systems was $5,060/kW in 1998, $3,950/kW in 2000, and $3,400 per installed kW of alternating-current ouput in 2002—a decrease of nearly 10% per year in nominal terms—so it appears that in the reasonable illustrative case offered by Hoff (especially bearing in mind that a substation application offers greater economies of scale than a residential one), actual market conditions for a decision-maker *already* meet these cost targets. Such dramatic price decreases are both a benefit to distributed resources and a competitive threat to centralized resources, as described in the following section.

As a final illustration of the importance of fast, granular resources, consider a perfect distributed generation resource that can be built in exactly the increments needed to meet annual load growth, with a one-year lead time—shorter than that of a larger central station. On those assumptions, the following table shows the percentage increase in the net-present-value cost of the central source compared with a distributed source *with the same unit capital cost* ($/kW). For example, if the central source has a capacity increment equivalent to six times the annual load growth, and a four-year lead time, it carries an effective 45% cost premium compared with a same-$/kW distributed source. Conversely, in this situation the distributed generator could cost 45% more per kW and still yield the same net-present-value capital charge as the central source. The only difference is in their lead time and their "lumpiness": the central resource costs more because it must be built earlier and because it has excess capacity until load growth catches up, as illustrated earlier in Figure 2-4. This calculation, however, is not as flexible and inclusive as Hoff's analytic solution above, as illustrated in Figure 2-11, so that form is recommended for practical calculations.

Table 2-1: Smaller can cost more but can make more money
Net-present-value increase in benefit (percent) of a small resource with a 1-year lead time, compared to a large resource whose incremental capacity is the "size ratio" times annual incremental load growth.

Size ratio	Large resource lead time (years)				
	1	2	3	4	5
1	0%	5%	10%	16%	22%
2	5%	10%	16%	22%	28%
3	10%	15%	21%	27%	34%
4	15%	20%	27%	33%	40%
5	20%	26%	32%	39%	46%
6	25%	32%	38%	45%	53%
7	31%	37%	44%	52%	60%
8	36%	43%	50%	58%	66%
9	42%	49%	57%	65%	73%
10	48%	55%	63%	72%	81%

Source: J N Swisher, "Cleaner Energy. Greener Profits: Fuel Cells as Cost-Effective Distributed Energy Resources" (RMI, 2002) *www rmi org/sitepages/pid171 php*

2.2.2.3 Technological obsolescence

Technological change is very rapid. During the 1990s, the aeroderivative gas turbine, an offshoot of military jet engine R&D, halved the long-run marginal cost of fossil-fueled power generation, captured most of the market for new capacity, and triggered industry restructuring by making more acutely visible the spread between cheap new power and costly old power. What might happen next? Mature backpressure turbines, new microturbines, and emerging fuel cells promise still cheaper power (134), especially when their waste heat is harnessed. The whole proton-exchange-membrane fuel-cell revolution is based largely on better membranes, lower pressures, higher performance, and much lower cost (largely via an order-of-magnitude reduction in catalyst loadings, plus design for

Benefits

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.*

manufacturing and assembly). Many of these developments were unforeseen a decade ago. Similar breakthroughs seem possible in manufacturing high-temperature molten-carbonate and solid-oxide fuel cells. Completely new kinds of photovoltaics based on inherently cheap materials are also emerging, based, for example, on sulfur, polymers, self-assembling structures, synthetic organic molecules, or chlorophyll analogs. Many other technological surprises are increasingly likely as more and smarter technologies are fused into new combinations. Even the possibility of wholly new energy sources, based on an improved understanding of basic physics, cannot be excluded.

Amid such flux, the smaller and faster the units ordered, the less the risk of large capital commitments to technologies that are obsolete and uncompetitive even before they're installed. Sinking less capital in costly, slow-to-mature, slow-to-build projects, and inflexible infrastructure reduces financial regret, and may also shrink the institutional time constant for getting and acting on new information. Thus less capital is tied up at any given time in a particular technology at risk of rapid obsolescence; a larger fraction of capacity at any time can use the latest and most competitive designs; and the associated organizations can learn faster.

The value of the resulting risk reduction may be hard to quantify, because the nature and size of the technological risk is by definition unknowable. Yet that value features prominently in the thinking of strategists in such industries as telecommunications and information systems. It should be no less a core element of strategic planning for electricity. There is also a link between unit scale, the pace of technological improvement, and economics. 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. As with electronics, then, the lessons learned drive continuous improvements that can be rolled incrementally and immediately into successive modules—not filed away for the next generation of engineers (if they remember) to apply to the next giant unit.

Obviously such agile technologies also offer far greater economies of mass production—less like giant bridges, more like computers. They move labor from field worksites to factories, offering far greater scope for productivity gains—like building cars, not cathedrals. They exploit modern and agile manufacturing techniques, highly competitive innovation, standardized parts,[17] and commonly available production equipment shared with many other industries. Their short construction cycles minimize the big-project headaches of workforce turnover and retraining. Their far less complex construction management draws on a deeper and cheaper talent pool.

All these attributes interact. They also increase the likelihood that more ponderous competing technologies may become obsolete and need to be written off before the end of their planned amortization lifetimes. The displacement, already underway, of operating and unamortized nuclear plants by combined-cycle gas turbines (which can be built and run more cheaply than just operating and repairing the average nuclear plant) offers a sobering lesson. Such lessons in turn make the capital markets wary of nuclear-like assets whose fair market value may depend far less on how far along they are in their projected engineering or accounting lifetimes than on the pace of technological evolution among competing technologies. Wary capital markets mean higher discount rates, costlier capital, and reduced competitiveness.

In general, too, central thermal power stations have neoclassical supply curves—the more units you build, the *more* each one costs—for reasons fundamental to democratic societies (§ 1.2.2, Figure 1-8). In contrast, efficiency and dispersed renewables perceived as benign have experience curves. For PVs, for example, each doubling of cumulative production has *cut* real marginal cost by nearly one-fifth. In any long-run competition between these two types of technologies, with their fundamentally different processes of both technical innovation and public acceptance, the more ponderous and unpopular ones are likely to lose. We return to this issue in Section 2.4.10.

2.2.2.4 Regulatory obsolescence

The cost, siting, and even practical availability of technologies depends on regulatory requirements, tax rules, and other public policy. Continuous conflicts between various groups amidst a swirling and ever-changing mass of environmental, social, and economic concerns make the regulatory process often unpredictable in detail (though often rather predictable in general trend), and hence a source of risk just as

[17] *Business Week* (84) reports that the U.S. military's wider adoption of standard commercial parts has reduced availability lags from months to hours and cut costs by fourfold or more

DATA REQUEST RESPONSES BY THE SIERRA CLUB

PSC CASE NO. 2006-00472

EKPC'S FIRST DATA REQUEST DATED JULY 25, 2007

REQUEST 11

RESPONSIBLE PERSON: Geoffrey M. Young

Request 11.

On page 40, lines 9-11, you state 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." Please explain how EKPC is presently being "punished financially… if it enters into contracts with cogenerators or small power producers." Please explain how decoupling/SR will stop or mitigate this financial punishment for entering into contracts with cogenerators or small power producers.

Response 11.

In the summer of 2005, I performed a spreadsheet-based analysis of the financial impacts of statistical recoupling (SR) under a range of scenarios. The analysis was presented in a memo dated August 5, 2005, to Jason Bentley, who at that time was the Executive Director of the Kentucky Office of Energy Policy. I had had one meeting with him to discuss decoupling, SR, and the problem of perverse financial incentives, and he had requested an analysis of the potential impacts of SR on electric rates. A copy of this memo is included below.

The scenario that is most relevant to this information request is Scenario C, which envisions the installation of a 150-MW cogeneration unit by an industrial firm. The hypothetical utility's base revenues for the three-year period were $2,043 million; the negative impact on the utility resulting from the cogeneration facility over the three-year period under the traditional ratemaking approach would have been a reduction of $57 million, or $19 million per year. This financial impact stems from the loss of electricity sales by the utility, and its concomitant difficulty in covering its fixed costs. Under SR, the impact of the cogeneration facility over the three-year period would have been a reduction in net revenue of only about $4 million, or a little over $1 million per year on average.

In brief, SR mitigates the financial punishment for entering into contracts with cogenerators or small power producers by allowing the utility to raise rates slightly to recover the revenue that is lost as a result of events that are not reflected by variables included in the SR formula. Neither the enhancement of DSM program impacts nor the installation of cogeneration facilities is reflected in the SR formula, so in such cases it would fulfill its intended primary function of decoupling revenues from sales of electricity.

MEMORANDUM

TO: Jason Bentley, Executive Director
Office of Energy Policy

COPIES TO: Bob Amato, Steve Boyce, John Davies, Andy McDonald, Ben Perry, Richard Raff, Jeff Shaw, Wade Helm, Ray Barry, Tom Fitzgerald, LaJuana Wilcher

FROM: Geoff Young
Sierra Club

DATE: August 5, 2005

SUBJECT: Estimated impacts of ratemaking reforms for energy efficiency

The most important question that you and PSC staff members have raised about statistical recoupling (SR) is whether the impacts on customers' rates would be excessively high. The purpose of this memo is to present a simple financial spreadsheet, based on the work of Eric Hirst, that enables one to estimate impacts that would occur under a range of different assumptions. I used the spreadsheet to show the effects of implementing:
a) SR without demand-side management (DSM) programs;
b) SR plus DSM programs; and
c) SR plus a cogeneration facility installed by an industrial firm.

<u>Background: Kentucky's experience with decoupling</u>

Before describing the spreadsheet and scenarios, however, it may be helpful to address one of the other questions that arose during our discussion about LG&E's experience with decoupling in Kentucky, i.e.: Once the utility's revenue was decoupled from the amount of energy it sold, to what was it recoupled?

I looked up the residential customer tariff that had been in effect in LG&E's service territory during the period from 1994 through 1998. The cost recovery method that the PSC had approved for demand-side management (DSM) programs 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 2%, for example, the allowable non-variable revenue from the residential class would be boosted by 2%.

(2) the allowable revenue was multiplied 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.

Because these formulas can be somewhat dry and hard to understand, it may be helpful to translate the messages being sent by the PSC 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 energy we will kick you in the teeth." The implicit message the PSC 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 only, if you help customers save energy we will stop kicking you in the teeth; instead, we will give you a small reward. In regard to all of your other customers in the non-residential sectors, if you help them save large amounts of energy we will continue to kick you in the teeth as we have for the past 60 years." When the PSC approved the elimination of decoupling in 1998, 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 customer classes and will kick you in the teeth if you help your customers save energy." Although these translations into words may seem dramatic, they clearly express the financial incentives that various ratemaking formulas convey to utility company executives.

Decoupling Options

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); 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 was of the second type, revenue-per-customer decoupling.

Two problems with 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 they also change the allocation of certain risks between the utility and its customers, most notably the risks relating to weather and economic recessions. If the weather is severe and energy usage increases, during the next period the decoupling formula will lower the 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 revenues 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 in Maine, the rate effects of such factors have dwarfed the effects of energy efficiency programs.

Statistical recoupling (SR) addresses these issues and reduces the size of the rate fluctuations. 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 analysis is performed, using the past 10 or 20 years of data, of 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 model also includes a first-order autoregressive term solely for the purpose of reducing the standard error in the model's other coefficients. The allowable revenues for subsequent years are determined by using the same formula and coefficients in conjunction with each year's variable data. *Ibid.,* pp. 33-36. The result is that revenues are decoupled from sales – i.e., the PSC stops kicking the utility in the teeth for helping customers save energy – and the year-to-year price fluctuations that can result from other forms of decoupling are moderated. Statistical recoupling appears to be the solution that would be most beneficial to all energy utilities in Kentucky.

Eric Hirst noted one secondary issue related to revenue-per-customer decoupling: "With RPC decoupling, it may be necessary to agree on an estimate of per-customer growth in electricity use (expressed in percent per year). Statistical recoupling has no predetermined growth-rate factor that remains constant between rate cases." *Ibid.,* p.53. It should be noted that a disagreement about the proper magnitude of LG&E's growth-rate factor eventually led some of the parties in the LG&E DSM Collaborative, including the utility itself, to propose the elimination of decoupling.

As Sheryl Carter noted, "Eliminating the disincentive is necessary, but not sufficient." While decoupling or SR formulas "make utilities neutral to investments that reduce throughput, they do not provide the utilities with incentives to actively promote energy efficiency, distributed resources, or other energy policy goals. Additional incentives or mechanisms are necessary to promote active investment in these areas... Strong performance-based incentives could also be established to deliver cost-effective savings, distribution enhancements, and other least-cost system values." ("Breaking the Consumption Habit: Ratemaking for Efficient Resource Decisions," *The Electricity Journal*, December 2001, p.70) In other words, in addition to statistical recoupling, the PSC should include factors in the rate formula that enable utilities to share in the savings that customers obtain – some jurisdictions give utilities a revenue boost equal to 15% of the customers' savings – and to recover prudently-incurred DSM program costs. Over the past 25 years, methods have been developed to estimate customers' savings. The Kentucky Division of Energy and several energy service companies have experience working with the International Performance Measurement and Verification Protocol (IPMVP), which provides a method for verifying energy savings. A brief overview of the

IPMVP is provided by Satish Kumar, "Measurement and Verification of Energy Savings," *Energy User News,* December 8, 2000.

Implementing the Necessary Ratemaking Reforms in Kentucky

The most straightforward way to change the ratemaking formulas to implement statistical recoupling, shared savings factors and DSM program cost recovery factors is for the PSC to issue an order scheduling a series of rate cases for each energy utility in Kentucky – electric and gas – for the sole purpose of changing the rate structures. The order should specify that the magnitude of the utility's revenue requirement is not at issue, nor is the allocation of revenue between the various classes of customers, but only the rate structure. This would eliminate almost all of the complex, contentious and time-consuming issues and testimony that typically accompany general rate cases, a phenomenon I have called "dueling accountants." In my view, the PSC would have the authority, under KRS 278.260, to initiate such proceedings on the grounds that the existing rate structure is not fair, just and reasonable because: 1) It unjustly punishes utilities financially for working with their customers to implement cost-effective measures that would significantly reduce energy use; and 2) It is contrary to the intent of 16 USC Section 2621(8), which states that public service commissions should set rates so that investments in DSM are at least as profitable as investments in new power plants. It is clear to me that the Commission has the legal authority to implement regulatory changes in Kentucky's energy utility sector that are called for by Federal law.

To summarize these comments on energy efficiency and utility regulatory reform:

- Improved energy efficiency is the largest, most cost-effective, and most environmentally sound energy "source" for the Commonwealth.
- The potential of DSM in all customer classes extends far beyond the existing limited programs.
- The traditional ratemaking framework rewards utilities for selling more energy and kicks them in the teeth if they help customers use energy more efficiently.
- The best solution is statistical recoupling and shared-savings incentives, which need to be applied to all energy utilities in Kentucky.
- The essential reforms can be implemented unilaterally by the PSC via a series of limited rate cases that deal with rate structure alone.
- All parties can benefit significantly by working together to reduce waste.

Estimated Impacts of Implementing Statistical Recoupling

Eric Hirst's report, *"Statistical Recoupling,"* contains a numerical example of a Utah electric utility company that implements SR in 1990. The first step involves the development of a statistical model of the key determinants of electricity sales. For purposes of his example, Hirst used quarterly data from 1978 through 1989. He then applied the formula to the years 1990, 1991 and 1992. A linear regression using aggregated data for all customer classes yielded the following preferred formula:

Total electricity use (GWh/quarter) =
-564 (a constant)
+ 0.00660 * the number of customers
+ 0.113 * the number of heating degree days
+ 0.347 * the number of cooling degree days
- 61.7 * the retail price of electricity
+ 177 * a measure of industrial output

Hirst's model also includes a first-order autocorrelation term solely for the purpose of reducing the standard error in the model's other coefficients. For the sake of simplicity, however, the autocorrelation term has been set to zero in the attached spreadsheet.

A. The first scenario in the attached spreadsheet illustrates the effect of implementing SR in the absence of DSM programs. Gross energy use increases gradually from 12,398 GWh in 1990 to 13,427 in 1992. The average retail base price is set by the last rate case. The year-to-year changes in the retail base price reflect the changes; both within and across customer classes, in the relative amounts of electricity used. (*Ibid.*, p. 34)

The second part of the first scenario illustrates the implementation of SR. The actual data for the variables in the formula are shown for the three years, 1990-92. Because the formula uses the real electricity price rather than the nominal price, a price deflator must be applied. Applying the formula to the 1990 data yields allowed electricity sales of 12,609 GWh. This is 1.7% higher than the actual sales. The SR approach then adjusts next year's electricity price by a percentage that reflects the fixed-cost component of the retail electricity price. According to Hirst, the fixed cost component typically accounts for 50% to 75% of the retail price. For purposes of this spreadsheet, I have assumed that the fixed cost component is 62.5% of the retail price. The base price for 1991 is therefore adjusted upward by 0.625 times the 1.7%, which equals 1.1%. In this example, the price adjustment would come out to 0.06 cents per kWh. This raises the 1991 retail price from $.0536 to $.0542 per kWh.

The SR formula is then applied again at the end of 1991 to determine the price adjustment to be applied to the 1992 base price. In this case, the formula yields allowed sales for 1991 of 12,930 GWh, which is 0.7% higher than the actual sales of 12,839 GWh. The base price for 1992 is adjusted upwards from $.0512 to $.0514 per kWh, an increase of 0.4%. Applying the SR formula to the 1992 data yields a price decrease of 0.06 cents per kWh to be applied to the 1993 base price.

The overall impact of applying SR in the absence of DSM or cogeneration is relatively minimal. The three-year total revenue under SR in this example happened to be about $10 million higher than the base case, but approximately $7 million of that amount would be refunded to customers during 1993. The primary objective – decoupling utility profits from sales – has been accomplished with negligible swings in the electricity price.

B. The second scenario illustrates the use of SR in the context of a set of fairly large-scale DSM programs. Most of the DSM-related data for this scenario was taken from a second report on SR by Eric Hirst and co-author Eric Blank, titled *Regulating As If Customers Matter: Utility Incentives to Affect Load Growth*, January 1993, Land and Water Fund of the Rockies, Boulder, Colorado. The Commission has a copy of this report because it was filed by the Kentucky Division of Energy in response to a data request in Case No. 2003-00433 and 2003-00434.

This report developed a numerical model for a hypothetical Rocky Mountain electric utility. The retail price structures they used were based on the same utility modeled in the other Hirst report cited earlier, as well as the specific tariffs for the residential and secondary general rate classes of Public Service Company of Colorado. (*Ibid.*, p. 8)

The hypothetical 3-year DSM program they analyzed had the following characteristics:

- It reduces demand by 20 MW in the first year, 30 MW more in the second, and 40 MW more in the third year, for a cumulative demand reduction of 90 MW.
- It has a conservation load factor of 50%.
- It reduces energy use by 88 GWh in the first year, 131 GWh more in the second, and 175 GWh more in the third year, for a cumulative energy reduction of 394 GWh per year (in the third year) and a cumulative total of 701 GWh saved over the three-year period.
- It costs the utility $1,200 per kW to implement, so the DSM program costs are $24 million in the first year, $36 million in the second, and $48 million in the third year. The levelized DSM cost is 3.6 cents per kWh.
- Assuming a discount rate of 10%, the net present value of the program cost is $96 million, the total resource benefits are $177 million, and the benefit/cost ratio according to the Total Resource Cost (TRC) test is 1.8.

(*Ibid.*, pp. 43-46)

I fed this DSM-related information into the spreadsheet I had developed based on Hirst's report, *"Statistical Recoupling: A New Way To Break the Link Between Electric-Utility Sales and Revenues."* The first scenario in Section B illustrates the effects of the type of DSM cost recovery policy in effect for utilities in Kentucky today. Instead of using a decoupling or statistical recoupling formula, the PSC currently allows utilities such as LG&E, KU and ULH&P to recover DSM program costs, DSM lost revenues, and a shareholder incentive. In the spreadsheet, I assumed the shareholder incentive is set equal to 10% of the DSM program cost.

The spreadsheet calculates the impact of the DSM program on the retail price by adding up all of the recoverable costs and dividing it by the amount of energy sold. The impact on the retail price is 0.20 cents/kWh in the first year, 0.38 cents/kWh in the second, and 0.52 cents/kWh in the third year. By the third year, the impact is thus approximately equal to 10% of the retail price. The fact that the TRC ratio is greater than 1, however, indicates that the sum of ratepayers' bills in the long run would be lower than they would have been if additional power plants had been built instead. Still, the magnitude of the price impact suggests why no utility company in Kentucky has yet proposed a set of DSM programs that are as large as in this scenario.

There are additional problems with this approach. The utility's profits have not been decoupled from sales. It still has a powerful economic incentive to boost sales at all times. The calculation of lost revenues is likely to be complex and contentious, and will depend on engineering estimates of energy savings as adjusted by subsequent impact evaluation studies. Basing the shareholder incentive on the amount spent on DSM reduces the economic incentive for the utility to operate the most efficient programs possible.

C. The third scenario estimates the impact of a cogeneration facility installed by an industrial firm in the utility's service area. The purpose of the cogen unit would be to provide both electricity and heat for one or more processes at the industrial plant. Kentucky's existing DSM statute, KRS 278.285, does not specifically include cogeneration in its definition of demand-side management. Cogeneration has the potential to put more than twice the fraction of energy in the fuel to productive use than a central power plant would. There are very few cogen facilities in Kentucky, in part because the PSC has allowed utility companies to erect financial barriers against potential cogenerators.

In the base case (without SR), an industrial firm installs a 150-MW cogen unit. To calculate the reduction in peak demand, I assumed that there was a 95% probability that the cogen unit would be operating during the utility's peak load hour. To calculate the amount of electrical energy saved, I applied the same load factor (50%) as in Eric Hirst and Eric Blank's DSM scenario. The cogen unit reduces the utility's sales by 627 GWh per year. In the short run, revenues are reduced by the fixed-cost component of this quantity of energy. The short-term reduction in net revenue to the utility is approximately $19 million per year. In reality, the utility would apply various charges to the industrial firm – the "financial barriers" I referred to above – but for purposes of this example I have set these charges equal to zero. In the long run, the addition of cogeneration in the utility's service area would postpone the need for additional utility power plants, saving all ratepayers money.

The financial impacts of cogeneration under SR are significantly different. The unexpected reduction in revenues during 1990 give rise to an increase in the electricity price of 0.24 cents/kWh above the 1991 base price. Similarly, the base price would be adjusted upward by 0.18 cents/kWh in 1992 and 0.08 cents/kWh in 1993. The utility's total short-term revenue loss would be only about $4 million over a three-year period, compared to $57 million in the cogeneration base case. The utility would still have a slight economic incentive to oppose cogeneration, but SR would eliminate the large bulk of the impact. The utility might even recognize that it might be worth $1 million a year to delay the need to provide 142 MW of additional capacity. Alternatively, the utility might find it beneficial to sell the energy saved by the cogen facility off-system.

Conclusions and Recommendations

1. The most important action that the Governor and the Public Service Commission need to take is to communicate clearly that Kentucky is serious about harvesting the vast potential energy efficiency gains that can be made throughout the Commonwealth.

2. Part of this message needs to be addressed to utility companies, as follows: If you get serious about helping your customers use energy more efficiently, the government will ensure that you are not penalized financially, as has been the case for almost all of the past seven decades. In fact, the PSC will implement the Federal law that states that the utility's lowest-cost plan should also be its most profitable plan.

3. Some form of decoupling is necessary to remove the perverse incentives from the traditional system of setting rates. The most advantageous form of decoupling is statistical recoupling, or SR.

4. In addition to the removal of existing disincentives, utilities will need positive financial incentives to help customers reduce their bills for energy services.

5. The PSC can implement the necessary regulatory changes on its own authority without the need for additional legislation.

6. The Governor can play a positive role by stressing the importance of this issue to the PSC and to the utility industry in Kentucky.

Statistical Recoupling Quantitative Scenarios

Determinants of Electricity Consumption

SR Formula: Total electricity use (GWh/year) =	
Constant	-2254.3
+ Number of customers x	0.0264
+ Heating degree days x	0.113035
+ Cooling degree days x	0.346906
+ Retail real electricity price x	-246.893
+ Industrial output x	176.922

A. Implementing SR formula with no DSM

1) Base case - No SR and no DSM	Year: 1990	1991	1992	
Gross sales (GWh)	12398	12839	13427	
DSM effect (GWh)	0	0	0	
Net sales (GWh)	12398	12839	13427	
Average retail base price ($/kWh)	0.0538	0.0536	0.0512	
Revenues (million $)	667.0	688.2	687.5	2042.6

2) Using statistical recoupling (no DSM)

Number of customers (thousands)	491	502	506	
Heating degree days	5370	5795	5153	
Cooling degree days	1346	1102	1189	
Industrial output	11.2	11.3	11.8	
Electricity price deflator	1.150	1.210	1.236	
Real electricity price ($/kWh)	0.0468	0.0448	0.0416	
Allowed sales (GWh)	12609	12930	13159	
Allowed revenues	678.3	700.4	676.7	
Ratio of allowed sales to actual sales	1.017	1.007	0.980	
Ratio accounting only for fixed price component	1.011	1.004	0.988	
Adjustment to next year's base price ($/kWh)	0.0006	0.0002	-0.0006	
Average retail price ($/kWh)	0.0538	0.0542	0.0514	
Revenues (million $)	667.0	695.5	690.5	2053.0

B. Implementing DSM programs							
1) with concurrent cost recovery (not SR)	Year: 1990	1991	1992	1993	1994	1995	1996
Gross sales (GWh)	12398	12839	13427				
Average retail base price ($/kWh)	0.0538	0.0536	0.0512				
Base revenues (million $)	667.0	688.2	687.5	2042.6			
Incremental DSM effect 3-year scenario (GWh)	88	131	175	0	0	0	0
Cumulative DSM effect (GWh)	88	219	394	394	394	394	394
Net sales (GWh)	12310	12620	13033				
Gross peak demand (MW)	2082	2156	2254				
Incremental DSM effect (MW)	20	30	40	0	0	0	0
Cumulative DSM effect (MW)	20	50	90	90	90	90	90
Peak demand after DSM (MW)	2062	2106	2164				
DSM program costs (million $)	24.0	36.0	48.0	0.0	0.0	0.0	0.0
DSM net lost revenues (million $)	3.2	8.0	14.4	14.4	14.4	14.4	14.4
DSM incentive (10% of program costs)	2.4	3.6	4.8				
DSM total program costs (million $)	29.6	47.6	67.2	14.4	14.4	14.4	14.4
DSM total resource benefits (million $)	2.1	6.8	15.1	18.0	20.9	23.9	26.8
Revenues after DSM adjustments (million $)	691.9	724.0	734.5				
Retail price after DSM adjustments ($/kWh)	0.0562	0.0574	0.0564				
Effect of DSM program on retail price ($/kWh)	0.0024	0.0038	0.0052				
3-year revenues				2150.4			

2) DSM programs with statistical recoupling							
Gross sales (GWh)	12398	12839	13427				
Incremental DSM effect 3-year scenario (GWh)	88	131	175	0	0	0	0
Cumulative DSM effect (GWh)	88	219	394	394	394	394	394
Net sales (GWh)	12310	12620	13033				
Gross peak demand (MW)	2082	2156	2254				
Incremental DSM effect (MW)	20	30	40	0	0	0	0
Cumulative DSM effect (MW)	20	50	90	90	90	90	90
Peak demand after DSM (MW)	2062	2106	2164				
Average retail base price ($/kWh)	0.0538	0.0536	0.0512				
Revenues (million $)	662.3	676.4	667.3				
DSM program costs (million $)	24.0	36.0	48.0	0.0	0.0	0.0	0.0
DSM total resource benefits (million $)	2.1	6.8	15.1	18.0	20.9	23.9	26.8
DSM shared savings incentive (20% of benefits)	0.4	1.4	3.0	3.6	4.2	4.8	5.4
Revenues after DSM adjustments (million $)	686.7	713.8	718.3				
Retail price after DSM adjustments ($/kWh)	0.0558	0.0566	0.0551				
Effect of DSM program on retail price ($/kWh)	0.0020	0.0030	0.0039				
Number of customers (thousands)	491	502	506				
Heating degree days	5370	5795	5153				
Cooling degree days	1346	1102	1189				
Industrial output	11.2	11.3	11.8				
Electricity price deflator	1.150	1.210	1.236				
Real electricity price ($/kWh)	0.0485	0.0473	0.0451				
Allowed sales (GWh)	12566	12867	13073				
Allowed revenues	701.0	736.7	728.7				
Ratio of allowed sales to actual sales	1.021	1.020	1.003				
Ratio accounting only for fixed price component	1.013	1.012	1.002				
Adjustment to next year's retail price ($/kWh)	0.0007	0.0006	0.0001				
Average retail price ($/kWh)	0.0558	0.0573	0.0557				
Revenues (million $)	686.7	722.6	726.5	2135.7			

C. Cogeneration scenario

1) Without statistical recoupling	Year: 1990	1991	1992	
Gross sales (GWh)	12398	12839	13427	
Average retail base price ($/kWh)	0.0538	0.0536	0.0512	
Base revenues (million $)	667.0	688.2	687.5	2042.6
Gross peak demand (MW)	2082	2156	2254	
Cogen effect on peak demand (95% availability)	142.5	142.5	142.5	
Cogen effect on energy (GWh)	627	627	627	
Net sales (GWh)	11771	12212	12800	
Reduction in variable costs	14.4	14.4	13.7	
Net revenues (million $)	647.7	668.9	669.1	1985.7
2) With statistical recoupling				
Number of customers (thousands)	491	502	506	
Heating degree days	5370	5795	5153	
Cooling degree days	1346	1102	1189	
Industrial output	11.2	11.3	11.8	
Electricity price deflator	1.150	1.210	1.236	
Real electricity price ($/kWh)	0.0468	0.0463	0.0429	
Allowed sales (GWh)	12609	12893	13128	
Allowed revenues	678.3	721.8	695.6	
Ratio of allowed sales to actual sales	1.071	1.056	1.026	
Ratio accounting only for fixed price component	1.044	1.035	1.016	
Adjustment to next year's retail price ($/kWh)	0.0024	0.0018	0.0008	
Average retail price ($/kWh)	0.0538	0.0560	0.0530	
Reduction in variable costs	14.4	15.0	14.2	
Revenues (million $)	647.7	698.7	692.4	2038.8

C. Cogeneration scenario

1) Without statistical recoupling	Year: 1990	1991	1992	
Gross sales (GWh)	12398	12839	13427	
Average retail base price ($/kWh)	0.0538	0.0536	0.0512	
Base revenues (million $)	667.0	688.2	687.5	2042.6
Gross peak demand (MW)	2082	2156	2254	
Cogen effect on peak demand (95% availability)	142.5	142.5	142.5	
Cogen effect on energy (GWh)	627	627	627	
Net sales (GWh)	11771	12212	12800	
Reduction in variable costs	14.4	14.4	13.7	
Net revenues (million $)	647.7	668.9	669.1	1985.7
2) With statistical recoupling				
Number of customers (thousands)	491	502	506	
Heating degree days	5370	5795	5153	
Cooling degree days	1346	1102	1189	
Industrial output	11.2	11.3	11.8	
Electricity price deflator	1.150	1.210	1.236	
Real electricity price ($/kWh)	0.0468	0.0463	0.0429	
Allowed sales (GWh)	12609	12893	13128	
Allowed revenues	678.3	721.8	695.6	
Ratio of allowed sales to actual sales	1.071	1.056	1.026	
Ratio accounting only for fixed price component	1.044	1.035	1.016	
Adjustment to next year's retail price ($/kWh)	0.0024	0.0018	0.0008	
Average retail price ($/kWh)	0.0538	0.0560	0.0530	
Reduction in variable costs	14.4	15.0	14.2	
Revenues (million $)	647.7	698.7	692.4	2038.8