#98

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF FLORIDA

In re: Petition of	)	Docket No. 910883-EI
Tampa Electric Company	)	
for a Determination of	)	
Need for a Proposed	)	
Electrical Power Plant	)	Filed: Oct. 31, 1991
Plant and Related	)	
Facilities	)	

DIRECT TESTIMONY OF PAUL L. CHERNICK ON BEHALF OF THE FLORIDIANS FOR RESPONSIBLE UTILITY GROWTH

Resource Insight, Inc.
October 31, 1991

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION AND SUMMARY

A. Witness Identification and Qualifications

Q: State your name, position, and business address.

A: I am Paul L. Chernick. I am President of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts. Resource Insight, Inc. was formed in August 1990 as the combination of my previous firm, PLC, Inc., with Komanoff Energy Associates.

Q: Summarize your qualifications.

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a Research Associate at Analysis and Inference, after 1986 as President of PLC, Inc., and in my current position at Resource Insight. I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; ratemaking for excess and/or uneconomical plant entering service; conservation program design; cost recovery for utility efficiency programs; and the valuation of environmental externalities from energy production and use. My resume is attached as Exhibit __PLC-1 to this testimony.

Q: On whose behalf are you testifying in this proceeding?

A: My testimony is being sponsored by the Floridians for Responsible Utility Growth (FRG).

B. Purpose and Summary of Testimony

Q: What is the purpose of your testimony?

A: My testimony addresses whether the Polk Unit One project proposed by Tampa Electric Company ("TECo" or "the Company") is necessary to meet the future needs of Florida ratepayers. My testimony focuses on whether TECo has adequately developed, considered, and integrated alternatives to the Polk Unit One project into its long-range resource planning. Specifically, my testimony considers if the need for new supply resources could be deferred or displaced by additional demand-side resources not included in the Company's integrated resource planning.

Q: Please summarize your conclusions.

A: TECo has considered only a narrow set of options in selecting the source of supply proposed at this time. The Company has neglected the wide range of resource alternatives it could choose from, failing to consider reasonable options available to meet its service obligation reliably and efficiently at least cost. This failure to prepare, compare, and pursue a full range of options actively renders its application deficient.

One consequence of this deficiency is that TECo is unable to establish that the Polk Unit One project is the least-cost option for meeting future demand for electric service. Specifically, TECo has not established that its resource plan includes all economical demand-side resources available in its service territory. On the contrary, the experience of other utilities strongly indicates that TECo could obtain much more energy and capacity from cost-effective demand-side options than currently contained in its resource plan. Thus, the Company has not established that a combination of demand-side resources and alternative supply options could not meet the same need as Polk Unit One at a lower overall cost than building and operating the Polk Unit One project. Nor has it established that the acquisition of additional demand-side resources could not economically delay the need for Polk Unit One generation.

Q: Summarize the major deficiencies you find in TECo's demand-side resource planning.

A: Several deficiencies in TECo's demand-side planning undermine the Company's ability to acquire all cost-effective DSM. These deficiencies include the following:

- TECo's economic screening of demand-side options is biased and inconsistent. The

Company relies primarily on the restrictive and discriminatory no-losers test to assess the cost-effectiveness and suitability of available demand-side resources. Moreover, TECo understates the benefits of demand-side resources in part by failing to incorporate specific estimates of avoided transmission and distribution (T&D) costs and the environmental costs of supply displaced by DSM.

- TECo is not comprehensively assessing, targeting, and pursuing energy-efficiency resources. TECo's piecemeal pursuit of savings will unnecessarily raise costs and reduce savings achieved from demand-side resources.

- TECo neglects large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, TECo loses them. Such lost-opportunity resources arise when new buildings and facilities are constructed, when existing facilities are renovated or rehabilitated, and when customers replace existing equipment at the end of its economic life. To make matters worse, TECo's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- TECo's programs are too weak to overcome the pervasive market barriers that obstruct customer investment in cost-effective efficiency measures. Incentives are not high enough and programs do not address many barriers.

Q: What do you conclude regarding additional demand-side savings available for acquisition by TECo?

A: To assess TECo's future need for capacity, I project the levels of DSM that could be reasonably expected if TECo developed comprehensive programs with the same intensity as those developed by collaboratives in other states. By the winter of 1995/96, I estimate TECo could increase the total peak-demand savings from DSM by 96 MW, or 20% of the approximately 482 MW the Company projects in its 1991 Need Determination Study (NDS). TECo's intensified acquisition of demand-side resources could produce even larger increases in energy savings from DSM. By 1996, TECo's DSM programs could generate energy savings of 720 GWh/yr, more than a three-fold increase over the level contained in TECo's 1991 NDS (including savings from earlier programs). If we assume that Polk Unit One operates at an 80% capacity factor, then the additional savings attainable are equivalent to the output of 73 MW or 33% of Polk Unit One capacity.[1]

If TECo were to acquire these additional peak savings, then its capacity requirements would decrease by the equivalent of the first 150 MW of Polk Unit One. Thus, the project could be scaled back to 75 MW, with capacity first required in 1996/97.[2] More importantly, the magnitude of

---

[1]Assuming an 80% capacity factor, Polk Unit One will generate 1542 GWh per year. Assuming a 150 MW CT (NDS, p. 7) operating at a 10% capacity factor (Conservation Plan, February 12, 1990, p. 8), or 131 GWh/year output, 1410 GWh/year is attributable to the HRSG. Thus, the additional energy savings I project are equivalent to 36% of the output of the heat recovery steam generator.

[2]In fact, the project could be scaled back to 70 MW. However, I have assumed that the minimum capacity that could be added to the system is 75 MW. This is consistent with the Company's assumption that generic CTs are added in 75 MW increments.

additional energy savings attainable might allow for the 220 MW combined-cycle facility to be replaced by a lower-cost 75 MW combustion turbine. Alternatively, these savings might allow the Company to delay the installation of the heat recovery steam generator and coal gasifier until that time when they become cost-effective.

Q: Have you determined the least-cost expansion schedule based on these additional savings?

A: No, I have not performed an integrated resource plan for TECo based on my estimates of additional available demand-side savings.

Q: Based on these findings and conclusions, what are your recommendations with regard to Commission action on TECo's petition for a Determination of Need?

A: I would recommend that the Commission decline to approve the Company's proposal to build Polk Unit One until the utility demonstrates (1) that it has undertaken to implement all economic energy efficiency and load management that could displace new power plants and (2) that Polk Unit One is still the least cost supply option available to meet any remaining requirements. Regardless of the Commission's ultimate decision on TECo's application in this proceeding, it should direct the Company to improve its planning and acquisition of demand-side resources before it commits to the construction of Polk Unit One. These reforms should include immediate and vigorous actions to: (1) acquire all cost-effective demand-side resources throughout its service area with comprehensive energy-efficiency programs, (2) provide adequate incentives and appropriate program designs to overcome market barriers, and (3) pursue "lost-opportunity" efficiency resources, which arise when customers construct new facilities or renovate and when they add or replace appliances and equipment. In addition, the Company should be directed to consider Polk Unit One avoidable in its economic evaluations of potential demand-side resources.

The Commission should advise the Company that until and unless it makes these reforms, its resource planning can not be considered either adequately integrated or truly least-cost. Without effective integrated least-cost planning, TECo cannot establish that resource additions are prudent or likely to be used and useful in providing future service to ratepayers. TECo will be at risk for investments and operating costs, including fuel, incurred due to the inadequacies in its conservation programs.[3]

Q: How have you organized the remainder of your testimony?

A: Section II examines the least-cost planning obligations TECo must satisfy for the Commission to approve its application under the Florida Statute. In this section I also present the economic rationale for utility investment in demand-side resources, and the program strategies adopted by leading U.S. utilities to acquire DSM savings comprehensively. In Section III, I delineate the Company's failure to pursue cost-effective demand-side resources systematically. I trace this failure to TECo's inadequate planning and design of demand-side programs. Section IV presents details of the improvements and expansion in demand-side resource acquisition that TECo should be directed to undertake, based on the activities of leading U.S. utilities. Using the plans of such utilities as a guide, I project the amount of DSM TECo should reasonably be expected to acquire through the end

---

[3]This is true for Clean Air Act compliance costs, as well as traditional supply costs.

of this century. Finally, I present my conclusions and recommendations in Section V.

II. TECO'S OBLIGATION TO PURSUE INTEGRATED RESOURCE PLANNING IN ORDER TO JUSTIFY A DETERMINATION OF NEED FOR THE POLK UNIT ONE PROJECT

A. TECo's Application and Requirements of Florida Statutes

Q: Please summarize TECo's proposal.

A: TECo has applied for a Determination of Need for the construction of a 220 MW integrated coal-gasification combined cycle (IGCC) generating facility at a site located in Polk County. The Company proposes to install a 150 MW advanced combustion turbine in 1995, followed by a 70 MW heat recovery steam generator (HRSG) and coal gasifier in 1996. The Company's projected resource balance with and without Polk Unit One is shown in Exhibit ___PLC-2.

Q: What statutory requirements have you reviewed in consideration of this request for a Determination of Need?

A: According to Section 403.519 of the Florida Statutes, the Commission's determination of need must "... expressly consider the conservation measures taken by or reasonably available to the applicant or its members which might mitigate the need for the proposed plant..." (§ 403.519). In

Section 366.81 the Commission is authorized to "... require each utility to develop plans and implement programs for increasing energy efficiency and conservation within its service area, subject to the approval of the commission." (§ 366.81).

Thus, the Commission is charged by statute with assuring that the long-range plans of all electric utilities include adequate measures to promote conservation.

Q: Has TECo met these requirements?

A: No. TECo has omitted a wide range of conservation resources from its resource plan and has failed to make a reasonable showing that no other cost-effective DSM alternatives to Polk Unit One exist. Although the Company is targeting a small amount of energy-saving efficiency resources, load management resources targeted to peak demand savings continue to dominate its DSM portfolio. As a result, the Company is missing opportunities to acquire DSM savings that can mitigate or delay the need for a baseload or cycling plant such as that proposed for Polk Unit One.

By failing to explore viable alternatives, TECo provides the Commission with little foundation upon which to review its plans as submitted. This severely restricts the Commission's ability to fulfill its responsibilities under Florida statutes. It may also result in the Company's ratepayers paying for unnecessary amounts of expensive generating resources. The utility's failure to develop and exhaust the potential for least-cost demand-side resources provides the grounds for outright rejection of TECo's application. At a minimum, failure by TECo to develop and incorporate least-cost options should lead the Commission to place strict conditions on any approval it grants the Company.

The Commission must not allow TECo to dismiss prospects for more comprehensive and flexible lower-cost options that may replace or delay the capacity TECo has proposed. As discussed below, TECo could scale back its current expansion plans by aggressively promoting direct investment in its customers' energy efficiency.

B. To demonstrate that a proposed resource is least-cost, TECo must show that it has exhausted the wide range of viable cost-effective demand-side alternatives

Q: What must TECo establish to substantiate the need for Polk Unit One?

A: The Company should have to establish that no combination of resources is available to meet the same need as the Polk Unit One project for less than the projected cost of building and operating the project over its economic life. In other words, TECo must show that Polk Unit One is the least-cost option for reliably meeting future demand.

Q: How do the principles of integrated least-cost planning relate to the Commission's assessment of the need for Polk Unit One?

A: The objective of least-cost planning is to minimize the <u>total</u> system costs of providing adequate and reliable service. <u>Integrated</u> planning extends the range of options beyond supply to include demand-side resources. A facility for which a utility seeks a Determination of Need forms a major part of the utility's long-range plan. Thus, the specific proposal and the plan of which it is a component are inextricably linked.

The requirement to minimize total costs of electricity services means that a particular project is needed only if it costs less than available, viable alternatives. This principle carries two important implications. First, it places an obligation on utilities to explore fully and develop adequately all reasonable options as viable alternatives to the facilities for which they seek a Determination of Need. Without such an obligation, a utility could simply neglect otherwise reasonable alternatives by failing to develop them sufficiently for full consideration. For example, the Company could present the Commission with a fait accompli by examining only its preferred option and failing to explore, develop, and analyze other competing supply technologies.

The second implication of least-cost planning for the Commission's consideration of the Company's application is that the Company must consider as resource alternatives combinations of smaller sources. Otherwise, a utility could sidestep a true evaluation of a variety of alternatives by opting to meet all its long-range resource requirements with a single large facility.

Q: Why should the Commission's consideration of resource alternatives extend to demand-side resources?

A. The objective of utility resource planning should be the minimization of the long-run costs of providing adequate and reliable energy services to customers. The minimization of total costs requires that utilities choose the resources with the lowest costs first, and then draw on progressively more expensive options until demand is satisfied.[4] But much of the demand being forecast by utilities arises because most customers are unwilling to spend more than a small fraction of the price they pay for using electricity on saving it. This market failure leaves a significant but unquantified potential for economical efficiency investment available for less than the cost of utility supply.

Least-cost planning therefore requires utilities to pursue savings their customers would otherwise miss. These efficiency gains are worth pursuing to the point that any further savings would cost more than supply -- counting all costs incurred by both utilities and their customers.

Q: Does least-cost planning obligate utilities to

---

[4]Uncertainty and risk complicate this task. Future demand is unknown. This makes some resources riskier than others. In general, larger resources with longer lead times carry greater risks for the system. Once utilities gain the capability to deploy efficiency resources, they can acquire them in small increments over short lead times. Some efficiency resources, such as programs to raise new buildings' efficiency, coincide with demand growth. More efficient loads generally are more stable loads, implying lower load uncertainty.

pursue only the most cost-effective DSM?

A: No. Least-cost planning requires utilities to pursue the most cost-effective resource plan. This goal implies that TECo should pursue all cost-effective DSM -- that is, all DSM available for less than the cost of supply it would avoid. Otherwise, stopping short of this goal would obligate the utility to make up for the foregone savings with more expensive supply.

Q: What role should the rate impact measure (RIM) or no-losers test have in determining the cost-effectiveness of a demand-side resource?

A: The no-losers test has no role in the economic screening of demand-side programs or the technologies incorporated in such programs. Use of the RIM will lead to the rejection of economical DSM.

Q: How does use of the no-losers test lead utilities such as TECo to reject cost-effective DSM?

A: DSM is cost-effective if its total benefits exceed its total costs, i.e., if it passes the total resource cost test. Under this test, costs include outlays for energy-efficiency measures themselves, plus utility program delivery costs. Benefits include the avoided costs of utility supply, plus any non-electric savings (such as natural gas, water, labor, etc.). A DSM measure or program satisfies the total resource test if its benefits exceed its costs because it will lower the total costs of providing electric service.

The no-losers test adds another dimension to the comparison: the revenue shifts caused by the sales reductions from energy conservation. These revenue losses are effectively added to the costs of DSM or subtracted from its benefits. DSM that passes the total resource cost test will usually appear less attractive under the no-losers test.

Depending on the relationship between avoided costs and retail rates, the no-losers test can completely rule out DSM, no matter how low its acquisition costs. For example, if retail rates exceed avoided costs, the "cost" of sales losses will exceed the benefit of avoided costs. In that case, DSM must have negative acquisition costs to pass the no-losers test. Such an absurd conclusion would automatically preclude demand-side resources that would lower total system costs.

Q: Should environmental externalities of generation be included in the total resource cost of supply avoided by DSM?

A: Yes. As recognized by the Commission in Docket No. 891324-EU:

> Externalities are costs or benefits of market transactions not reflected in prices. If a particular conservation program would reduce certain external environmental costs that can be reasonably quantified, these avoided costs should be recorded as a benefit when calculating the benefit-cost ratio for the Total Resource Test only.[5]

Q: Can environmental costs be "reasonably quantified", as required by the Commission?

A: The fact that several commissions and utilities around the country have adopted monetized values for externalities is strong indication that such externalities can be reasonably quantified. Externality values have been adopted by New York, Massachusetts, Nevada, California, and New Jersey regulators, as well as by the Bonneville Power Administration.

C. Need for utility investment in demand-side resources

Q. Why should utilities intervene in customer energy-use choices?

[5]Order, Docket No. 891324-EU, p. 2.

A. Customers typically require efficiency investments to pay for themselves in two years or less, while utilities routinely accept supply investments with payback periods extending beyond twelve years. In Appendix 1 to this testimony, I show that this "payback gap" has the same effect as an exceedingly high markup by customers to the societal costs of demand-side resources. The pervasive market barriers underlying the payback gap lead utility customers to reject substitutes for supply which, if scrutinized under utility investment criteria, would appear highly cost-effective.

Q. Are short-payback requirements confined to a few, relatively unsophisticated customers?

A. Not according to extensive research. As discussed in the handbook on least-cost utility planning prepared for the National Association of Regulatory Utility Commissioners:

> According to extensive surveys of customer choices, consumers are generally not motivated to undertake investments in end-use efficiency unless the payback time is very short, six months to three years. Moreover, this behavior is not limited to residential customers. Commercial and industrial customers implicitly require as short or even shorter payback requirements, sometimes as little as a month. This phenomenon is not only

> independent of the customer sector, but also is found irrespective of the particular end uses and technologies involved. ("Least-Cost Utility Planning: A Handbook for Public Utility Commissioners," Vol. 2, The Demand Side: Conceptual and Methodological Issues, December 1988, p. II-9)

Q. Why do customers act as if they attach high markups to efficiency investments?

A. Limited access to capital, institutional impediments, split incentives, risk perception, inconvenience, and information costs compound the costs and dilute the benefits of energy efficiency improvements. These factors interact to form even stronger barriers. Utilities can accelerate investment in cost-effective demand-side measures with comprehensive programs that reduce or eliminate these barriers.

Q. How can utilities substitute demand-side measures such as energy efficiency improvements for utility supply?

A. Customer demand for energy services such as lighting, space conditioning, and industrial shaft power can be met in a multitude of ways, involving varying combinations of electricity, capital, fuel, and labor. It is often possible to reduce the sum of these costs without compromising the level and quality of service by substituting capital behind the meter for capital behind the busbar. For example, if it costs less to save a kilowatt-hour (kWh) with a more efficient motor than to produce it with generating capacity, total costs will be lower if efficiency is chosen over production.

Q. Are such trade-offs between efficiency and consumption made automatically in the marketplace in response to price signals?

A. To some extent. With some simplifying assumptions, microeconomic theory predicts that pricing electricity at marginal cost will automatically lead to optimal resource allocation.

In reality, customers routinely decline efficiency investments which, if evaluated with a utility's economic yardstick, would appear to be extremely attractive resources. Based on utility price signals -- which often exceed estimates of long-run marginal costs -- typical customers require efficiency investments lasting as long as 30 years or more to pay for themselves within two years. By contrast, utilities routinely accept long-lived supply options with apparent payback periods of 12 years or longer. By forgoing low-cost efficiency investments, consumers compel utilities to expand supply at higher cost.

This disparity between individuals' and utilities' investment horizons constitutes a "payback gap" that leads to over-investment in electricity supply. Utilities can bridge the payback gap, thereby avoiding more expensive supply investments, by investing directly to supplement price signals.[6]

Q. Why does the payback gap imply that utilities need to invest in customer efficiency improvements?

A. Market barriers force customers to apply more exacting investment criteria to efficiency choices than utilities apply to supply options. Without utility intervention, the payback gap will lead customers to under-invest in efficiency and utilities to over-invest in supply. As the NARUC least-cost planning handbook states:

> Demand-side resources are opportunities to increase the efficiency of energy service delivery that are not being fully

---

[6]The 17-fold markup in the example in Appendix 1 means that an electric rate of 6 cents/kWh would not motivate a customer to spend 6 cents per conserved kWh. Rather, the customer would only invest in efficiency that to a utility would cost about 1/3 cent/kWh. Equivalently, a utility would have to set prices seventeen times higher than marginal cost to stimulate the customer response that is optimal.

> taken advantage of in the market. To make use of demand-side resources requires special programs, which try to mobilize cost-effective savings in electricity and peak demand. Without such programs, these savings would not have occurred or would not have materialized without significant delay, and in any case could not have been relied upon, forcing utilities to construct expensive back-up capacity and causing higher rates. (Id. at II.1; emphasis in original)

Explicitly acknowledging the payback gap leads to two conclusions about the potential for demand-side resources and strategies needed to realize it:

- Utility price signals are much weaker as a tool for stimulating investment changes than most analyses assume.

- A vast amount of economical efficiency potential remains for utilities to tap as demand-side resources.

Q. Please summarize how market barriers weaken price signals and leave a large potential for cost-effective utility investment in demand-side resources.

A. The NARUC handbook sums up this relationship as follows:

> The short-payback requirements for efficiency investments usually result from different combinations of these factors [market barriers]. But the multitude of dynamics involved explains why the payback gap is not just found for particular end uses or particular customer groups, but is so universal. It also explains why consumer investment[s] in efficiency and load management are not governed solely or even mainly by an economically efficient response to prevailing prices. For these reasons, the redesign of utility rates alone, or any other strategy limited to the correction of prices only, is insufficient to mobilize the bulk of demand-side resources. Direct intervention is needed to strengthen market mechanisms and remove institutional and market barriers. Id. at II.15.

These market barriers are discussed in more detail in Appendix 1.

D. The need for comprehensive strategies in planning and acquiring demand-side resources

Q: What do you mean by "comprehensiveness"?

A: I refer primarily to achieving all cost-effective efficiency improvements for each customer involved in a utility DSM program. In addition, utility programs should be comprehensive in addressing all customers and all market segments.

The Vermont Public Service Board defines DSM comprehensiveness in the following terms:

> Utility demand-side investments should be comprehensive in terms of the customer audiences they target, the end-uses and technologies they treat, and the technical and financial assistance they provide. Comprehensive strategies for reducing or eliminating market obstacles to least-cost efficiency savings typically include the following elements: (1) aggressive, individualized marketing to secure customer interest and participation; (2) flexible financial incentives to shoulder part or all of the direct customer costs of the measures; (3) technical assistance and quality control to guide equipment selection, installation, and operation; and (4) careful integration with the market infrastructure, including trade allies, equipment suppliers, building codes and lenders. Together, these steps lower the customer's efficiency markup by squarely addressing the factors that contribute to it.[7]

Q: Why is a comprehensive approach to demand-side resource acquisition a prerequisite for integrated least-cost resource planning?

---

[7] Vermont Public Service Board, Decision in Docket 5270, Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy, p. III-44.

A: This imperative is rooted in the least-cost planning objective of pursuing all achievable savings available for less than utility avoided costs. In effect, TECo should invest on the conservation supply curve for each customer's facility until the next kWh and/or kW of savings exceeds avoided costs. Only a comprehensive approach that pursues efficiency savings sector by sector and customer by customer, not measure by measure, will allow TECo to achieve the optimum amount of least-cost efficiency resources.

Q: How does the strategy you recommend differ from other approaches a utility might take to demand-side investments?

A: Buying efficiency savings is a markedly different proposition from selling or marketing conservation measures. The latter tends to concentrate on individual technologies. It often leads utilities to fragmented and passive efforts to convince customers to adopt individual measures that marketing research indicates they are most likely to want and accept. TECo's planning is typical of this approach. Another frequent but misguided objective is to seek savings from customers as inexpensively as possible. Such a strategy will neglect savings costing more than the cheapest conservation (say, 4 cents/kWh rather than 2 cents/kWh), but which are available at less than utility avoided costs (say, 6 cents/kWh.) Both alternatives, while intuitively attractive at face value, could well lead utilities to acquire more supply than least-cost planning criteria would justify.

Q: What are the practical implications of this "efficiency-buying" approach to utility demand-side investments?

A: Treating each customer as a reservoir of developable electricity resources leads to some important principles about the way to design and implement programs. Most importantly, successfully capturing economical energy efficiency opportunities requires that utility programs be comprehensively targeted. This means that utilities should generally address the entire efficiency potential of the customer, not just one end-use or measure. Otherwise, utilities would have to re-visit their customers many times over to tap all available, cost-effective efficiency savings. In the end, less of the efficiency resource would be recovered at higher costs than if the utility extracted all the efficiency potential one customer at a time.[8]

Addressing technologies and end-uses comprehensively among customers avoids two common mistakes in utility efficiency programs, both of which I found in TECo's plan:

- failing to account for interactions between technologies and end-uses; and

- "cream-skimming", neglecting measures that would be cost-effective at the time other measures are installed but which would be more expensive or impractical later.

Q: Why are comprehensive strategies needed to overcome market barriers to customer efficiency investment?

A: While individual customers may decline particular cost-effective efficiency measures for one reason or another, a multiplicity of barriers is likely to impede any class's exploitation of economically

[8] A clear analogy exists to the development of oil and gas resources or mining. The resource is limited, and careless extraction of one part of the resource can interfere with development of the rest of the potential.

feasible efficiency potential. Short of customizing a different program for every customer, utilities need to design programs that address the full array of obstacles preventing least-cost customer efficiency investments.

Q: Is it realistic to expect utilities to assume the responsibility for exploiting all customer efficiency opportunities, attempting to complete them in unified programs?

A: Yes. Treating efficiency potential thoroughly does not necessarily mean installing all measures in one visit. In fact, many successful programs start with a thorough site analysis and the installation of a few straightforward measures. The utility then follows up with a detailed investment plan for achieving the full potential. For example, when an existing chiller needs replacing, the utility may offer a rebate for a downsized, higher-efficiency chiller in conjunction with a comprehensive relamping project.

Nor is it essential that one program cover all end-uses for a particular customer group. Comprehensiveness should be judged by how completely a utility's full portfolio of programs covers relevant end-uses, options, and sectors.

For example, utilities may use several programs to cover residential efficiency potential. They target weatherization retrofits, new construction, and appliance replacement separately because of the different structure and timing of the decisions involved.[9] Such an approach is comprehensive if the two programs are linked where appropriate.

E. Need to target lost-opportunity resources explicitly

Q: What do you mean by lost-opportunity resources?

A: The Northwest Power Planning Council defines lost-opportunity resources as those "which, because of physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use."[10] On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or

---

[9]Appliance programs are often structured differently for appliances selected by ratepayers (e.g., refrigerators) and those selected primarily by contractors (e.g., water heaters, HVAC.)

[10]Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, Vol. 1, p. Glossary-3.

physical barriers to their later acquisition.[11]

Q: Are lost-opportunity resources important?

A: Yes. Acquiring all cost-effective lost-opportunity resources should be a utility's top demand-side priority for at least five reasons. First, the situations that create the potential for lost-opportunity resources are the leading source of load growth, and thus actually create requirements for new resources. Load growth is driven largely by customer decisions to add new or expand existing facilities, where a "facility" may be any building, appliance, or equipment. Second, lost-opportunity resources often represent extremely cost-effective savings, since only incremental costs are incurred to achieve higher efficiency levels. Third, acquisition of lost-opportunity resources cannot be postponed. Fourth, market barriers to customer investment in lost-opportunity resources are among the most pervasive and powerful. Fifth, lost-opportunity resources are the most flexible demand-side resources available to utilities. They tend to correlate with demand growth since rapid growth tends to correspond to construction booms and

---

[11] "Five Years of Conservation Costs and Benefits: A Review of Experience Under the Northwest Power Act," at 7.

facility expansion. Unlike any other option available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.[12]

Q: Where are lost-opportunity resources usually found?

A: One-time opportunities to save energy through improved energy efficiency arise in three market sectors:

- during the design and construction of new building space;

- when existing space undergoes remodeling or renovation; and

- when existing equipment either fails unexpectedly or is approaching the end of its anticipated useful life.[13]

---

[12]The Vermont Public Service Board recognized that "a utility committed to pursuing all efficiency opportunities that would otherwise be lost will automatically synchronize its new resource acquisitions with swings in resource need." Decision in Docket 5270, Investigation into Least-Cost Investments, Energy Efficiency, Conservation and Management of Demand for Energy, April 16, 1990, p. III-110.

[13]A fourth category of lost-opportunity measure, addressed earlier, arises in retrofit situations. Often there are measures that would be cost-effective to install in conjunction with other measures, but that

As observed by Gordon, et al.:

> If these opportunities are not pursued at a specific time, they will be much more expensive, much less effective, or impossible to pursue later. ... [lost opportunities] have a unique importance because they cannot be postponed.[14]

Q: What distinguishes a lost-opportunity measure from a discretionary DSM opportunity?

A: The two dominant factors that determine if a conservation measure is a lost opportunity measure are (1) the feasibility or cost premium of installing it later, and (2) the service life of the building or equipment involved. Id. Efficiency is inexpensive during construction, renovation, or replacement, when higher levels can be attained through design changes and incremental investments. Once these opportunities lapse, efficiency improvements often require existing equipment to be discarded and work to be redone in a retrofit

---

would not be economical to pursue in a subsequent visit or through a separate program. Frederick W. Gordon, et al., "Lost Opportunities for Conservation in the Pacific Northwest," undated, at 2.

[14] Gordon, op. cit., p. 2.

decision. In the case of new equipment such as appliances, all efficiency potential may be lost until the end of its useful life. (Id. at 9)

Q: How rapidly are these opportunities lost?

A: These opportunities represent rapidly vanishing resources because builders, businesses, and consumers are making essentially irreversible choices on a daily basis. The window of opportunity for influencing these decisions is quite short. For new commercial construction, this window may be a matter of weeks or months; for appliances, a utility's opportunity to acquire cost-effective savings may be limited to hours or at most days. The consequences of these decisions can last anywhere from a decade to a century.

Q. Have other utilities or regulators recognized the imperatives of lost-opportunities?

A. Yes. The Northwest Power Planning Council first urged Bonneville Power Administration and the region's utilities and regulators to pursue lost opportunities in its 1983 Plan. Its 1986 plan reaffirmed this recommendation in spite of a large capacity surplus.[15] In Vermont, the Public Service

---

[15] 1986 Northwest Plan, op. cit., at 9-28 through 9-30.

Board and the utilities it regulates are making lost-opportunity resources a top priority.[16] The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan."[17] The Wisconsin PSC also declared that utilities should not let such valuable yet transitory efficiency opportunities escape:

> The importance of improving the energy efficiency of commercial buildings as soon as possible must be emphasized. These buildings represent long-term investments (up to 70 years) which will significantly affect the use of energy once they are constructed. Retrofitting to achieve energy efficiency, as experience has shown, is usually expensive, if possible at all. Therefore the commission is not willing to allow these 'lost opportunities' for energy efficiency to continue unabated." (Fifth Advance Plan Order, op. cit., at 33-34)

Northeast Utilities has adopted this same perspective in its demand-side programs, which it developed under an unprecedented collaborative

---

[16]Vermont PSB Docket 5270, Vol. III, at 58-59, 92-102.

[17]See Order No. 22299, Case No. U-1500-165, January 27, 1989.

design process spearheaded by the Conservation Law Foundation. Utilities in Massachusetts and Vermont have oriented their demand-side strategies toward lost-opportunity resources.

Q: What incentives will maximize TECo savings from lost-opportunity resources?

A: Because of the brief window of opportunity typical of lost-opportunity resources and because of the permanence and magnitude of their savings, it is essential that utilities pay essentially the full incremental cost of lost-opportunity measures. As noted in Section II.F., this imperative has been recognized in collaboratively-designed DSM programs.

Q: Can you cite an example of a utility that has found on its own that incentives of 100% of incremental costs are effective?

A: Yes. Puget Sound Power and Light offers a prime example of a utility that has learned this lesson from its own experience. In its new commercial building program, program incentives were set initially at 50-80 percent of incremental measure costs. Puget decided to change its policy and now offers incentives equal to full incremental cost, up to a maximum of avoided costs, for this program.

Following is the rationale behind this change, as explained to Portland Energy Investment Corp.:

> We were getting about 50-60 percent of the people that we were talking to. But we were not even talking to the speculative building market. When it came down to accepting and installing the measures, cost was the deciding factor for owners: even among participants, owners were not installing all the measures that should have gone into the building because of measure costs. The comprehensiveness of the energy savings was being compromised. We believe that we can get an additional 20-30 percent of the people to participate with full-incremental cost incentives.
>
> We believe that without full incentives, in the long run, we would have lost as much as 80 percent of penetration into buildings. It is easier to attract owner-occupied buildings, where the owner has a stake in the savings, and full-incremental cost incentives would encourage the owner to become more aggressive on energy conservation. In the speculative building's market, we felt that we could lose as much as 100 percent of the market without full-incremental cost incentives.[18]

Puget's conclusions support my contention that incentives covering full incremental costs are needed to capture both sources of lost-opportunities: harder-to-reach customers who would

---

[18]Personal communication between Mac Jourabchi, PECI, and Syd France, PSP&L, 3/8/91.

not participate otherwise, and comprehensive measures that even participants would not otherwise install.

F. Pace, scope, and scale of DSM acquisitions of leading utilities

Q: What do you find from your examination of DSM plans by utilities with comprehensive program designs?

A: I find that such utilities are targeting large amounts of electricity savings compared to their projected demand growth. These sizable savings are associated with major financial commitments by sponsoring utilities. While aggregate DSM expenditures represent a significant share of total utility revenues, I also find that the savings these utilities are buying compare favorably to new utility supply -- especially when the costs of environmental externalities are included in the costs of such supply. Finally, the program plans of these leading utilities aim at achieving all cost-effective DSM savings from utility customers over time. Included in their program designs are such critical elements as financial incentives covering all or most of the costs of efficiency measures; hassle-free service delivery; and intense and focused marketing.

Q: Which are the "leading" utilities you rely on here?

A: I am referring to the plans of 7 utilities in the Northeastern U.S., primarily in New England, with DSM programs designed in collaboration with non-utility parties. The utilities examined here include Boston Edison (BECO), Commonwealth Electric, Eastern Utilities (EUA), New England Electric Service (NEES), Western Massachusetts Electric (WMECO), New York State Electric and Gas (NYSEG), and United Illuminating (UI).

Q: Why have you restricted your examination to these utilities in particular?

A: Unlike many other utilities in the U.S., these companies' plans follow the least-cost planning objectives of utility demand-side planning and acquisition discussed earlier. Accordingly, their program plans best represent the savings, expenditures, and program characteristics associated with truly comprehensive DSM plans.

1. Program savings and spending

Q: How much electricity are these collaboratively-designed DSM plans expected to save?

A: Exhibit __PLC-6 provides various measures of aggregate electricity savings for these collaborative DSM plans. To facilitate comparison with TECo, I have expressed the savings as percentages of peak load and energy sales and as percentages of growth in demand and energy. Total DSM savings as a fraction of cumulative growth in peak demand ranges from a low of 32% for BECO to a high of 81% for EUA. Energy savings range from 31% of cumulative sales growth for NYSEG to 63% for EUA. Obviously, the longer the program's duration, the higher the fraction of total electricity demand it will achieve. Thus, Exhibit __PLC-6 shows that UI's 20-year program plan generates total peak savings amounting to 20% of its projected peak demand. BECO's 5-year program achieves a 4% reduction in peak load.[19] In terms of energy savings, these collaborative programs generate between 4% and 16% of total sales.

Exhibit __PLC-5 provides expected savings figures for 1991.

Q: How much are utilities with collaboratively-designed programs planning to spend on them?

A: In general, spending ranges between 3% and 6% of total electric revenue, as seen in Exhibit __PLC-

---

[19] The differences are thus due more to the planning horizon than to ultimate targets.

4. Expenditures in the early years of long-range DSM plans are as low as 2.2% for NYSEG ($25.4 million) to as high as 5.3% for NEES ($85 million). Over time, average DSM expenditures range from 3.5% for BECO (which exclude expenditures on load-control programs which save no energy) to 6.7% for NYSEG.

Q: How much are these savings expected to cost?

A: Exhibit __PLC-7 provides aggregate cost estimates of expected electricity savings for several collaborative utilities. Using total program expenditures, this exhibit indicates that the gross cost of conserved electric energy ranges from 1.6 cents/kWh (for Com/Electric's non-residential programs) to 5.8 cents/kWh (for NEES' 1991 conservation portfolio).

Q: Explain how you calculated these figures.

A: First, I amortized DSM budgets over an estimated average measure life of 15 years to arrive at annualized DSM expenditure over the years of program savings. To compute the gross cost of conserved energy, I divided this amortized cost over the maximum annual energy savings.

2. Program strategies

Q: What is the overriding objective of these program designs?

A: All the collaborative program designs seek to achieve the maximum level of cost-effective savings possible by maximizing the level of cost-effective customer participation and by maximizing the cost-effective savings by program participants.

Q: What approaches are common to the collaborative program designs?

A: These plans share several essential characteristics. They are comprehensive in terms of measures targeted, customers treated, and strategies employed. Moreover, they offer much higher financial incentives to customers than has become the norm among typical utility DSM programs.

Q: Are such comprehensive approaches necessary for achieving high participation?

A: Yes, according to a growing body of research. This imperative is reflected in a recent study of utility experience with non-residential conservation programs. According to Nadel:

> Comprehensive programs can achieve very high participation rates (several program have reached 70% of targeted customers) and very high savings (one pilot program achieved 22-23% savings). In general, the

> highest participation rates and highest savings (as a percent of pre-program electricity use of participating customers) are achieved by comprehensive programs which combine regular personal contacts with eligible customers, comprehensive technical assistance, and financial incentives which pay the majority of the costs of measure installation.[20]

Nadel and Tress incorporate this finding into the strategies they develop for achieving statewide targets set by the New York PSC and State Energy Office. As they conclude:

> In order to obtain savings of this magnitude, a comprehensive array of conservation programs must be pursued aggressively, including programs directed at all major sectors, end-uses, and market types (e.g., retrofit, replacement, and new construction). Furthermore ... in order to obtain these savings [sic] will require a transition from traditional program approaches (e.g., audits and modest rebates) towards new program approaches (e.g., high rebates and direct installation services.)[21]

---

[20]Nadel, S., Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs For Commercial and Industrial Customers, Final Report prepared for the New York State Energy Research and Development Authority. April 1990, pp. 174, 183.

[21]Nadel, S. and Tress, H., The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs, Final Report prepared

a. Customer financial incentives

Q: How are customer incentive levels determined in these programs?

A: In general, incentives are set as high as necessary to maximize participation by eligible customers and ensure that participating customers maximize the penetration of cost-effective measures. This is because experience by utilities leads to the inescapable conclusion that, for most customer segments, maximum cost-effective savings will only be realized if utilities pay for the full incremental costs of efficiency measures. This finding is one of the major lessons learned from utility experience to date. With some exceptions, these utilities generally pay the full incremental cost of efficiency measures or full avoided costs -- whichever is less.

Exhibit __PLC-8 summarizes the customer incentives offered by these collaborative programs. Notice that in most lost-opportunity situations, utilities pay the full incremental costs of measures. This is true for new construction and

---

for the New York State Energy Research and Development Authority and the New York State Energy Office. November 1990, p. 9.

non-residential equipment replacement and building remodeling. This exhibit also shows that these leading utilities are paying the full costs of measures in direct installation programs that are targeted at hard-to-reach customers, such as low-income residential and small commercial customers.

NEES had developed substantial experience with programs with various incentive structures to tap the efficiency potential of market segments <u>prior</u> to the collaborative design process.[22] Yet, nearly all NEES programs now cover 100% of measure costs.[23] The one notable exception to this rule is in the

---

[22]For example, NEES had run side-by-side comparisons between custom rebate programs and demand-side bidding systems. It found that the custom rebate package was more cost-effective, achieved higher participation, and obtained greater electric savings than performance contractors. Hicks, E.G., "Third Party Contracting Vs. Custom Programs for Commercial/Industrial Customers", <u>Energy Program Evaluation: Conservation and Resource Management</u>, Chicago, August 1989, pp. 41-45. NEES had also previously run programs offering 100% financing for selected measures. For example, the Enterprize Zone program paid all lighting efficiency costs for small C/I customers and achieved 60% participation among targeted customers. Nadel and Ticknor, "Electricity Savings form a Small C&L Lighting Retrofit Program: Approaches and Results," <u>Energy Program Evaluation: Conservation and Resource Management</u>. Chicago; August 1989, pp. 107-112.

[23]See generally <u>Power by Design: A New Approach to Investing in Energy Efficiency</u>, submitted to the Massachusetts DPU by CLF on behalf of NEES, September 1989. NEES pays 100% of incremental costs in all residential programs, small C/I retrofits for customers under 100 kW, and all new construction across all sectors.

large commercial/industrial retrofit program, where the Company will "buy down" investments so their customers have a payback period of between 12 and 18 months.[24]

Likewise, Boston Edison uses full funding in order to acquire all cost-effective efficiency resources in most sectors. For example, BECo pays 100% of measure costs in direct installation programs and in new construction programs. One exception is 2/3 funding in residential lighting rebate programs (which supplement the direct installation program, similar to the approach in the residential lighting programs developed by Nadel and Tress). Another exception to the full-funding rule is in the non-institutional commercial/industrial retrofit program, where the utilities buy down efficiency investments to a one-year payback period. Finally, utilities buy down efficiency improvements in industrial processes to an 18-month payback in new industrial construction.

Q: Can you cite utility experience to support your conclusion that full utility funding is necessary to accomplish maximum cost-effective penetration?

---

[24]For comprehensive retrofits -- i.e., where the customer commits to all cost-effective measures -- NEES will pay 100% of measure costs.

A: Beyond Hood River, there is really no full-scale program experience that demonstrates maximum participation achievable from alternative utility investment levels. In the residential sector, only direct investment has proved to be effective in reaching high participation.[25] Most recently, NEES has obtained 50% participation in its Energy Fitness program offering direct installation to residential customers in Worcester, Mass. In the non-residential sectors, it is becoming increasingly clear that only fully-funded programs offering comprehensive assistance reach high customer participation and achieve high measure penetration. Programs offering only partial incentives without individualized marketing and

[25] Nadel observes that in general, "when financial incentives are high, substantial participation and savings rates can be achieved" from comprehensive programs. Nadel, Conservation Program, op. cit., p. 6. This observation even applies to relatively low-cost investments. The Santa Monica Energy Fitness Program in 1984-85 achieved 33 percent participation by offering free installation of up to three efficiency measures. Michigan replicated the Santa Monica approach by offering free installation of up to six measures. Participation averaged 49 percent (ranging between 36 and 59 percent). Kushler, et al., "Are High-Participation Residential Conservation Programs Still Feasible? The Santa Monica RCS Model Revisited", Energy Program Evaluation: Conservation and Resource Management. Chicago; August 1989, pp. 365-371. Note the coincidence between higher participation and the more comprehensive set of measures offered to participants.

close technical support do not succeed. In general, "rebate programs currently in operation have not been especially effective at promoting 'system' improvements, i.e., efficiency improvements involving the interaction of multiple pieces of equipment."[26]

Q: Is the customer incentive level the only factor influencing customer participation?

A: No. Many factors influence a customer's decision to install cost-effective efficiency measures. Although money may not be all that matters, it matters a lot. In fact, when non-financial factors such as marketing and technical assistance are held constant, raising the level of utility funding will increase participation. Nadel concludes:

> Data on the effect of different incentive levels are limited but show that providing free measures results in the highest participation rates. High incentives ... appear to promote greater participation than moderate incentives ... However, moderate incentives may not achieve higher participation than low incentives.[27]

---

[26]Nadel, Lessons Learned, op. cit., 184.

[27]Nadel, op. cit., p. 186.

Any ambiguity over the optimal incentive levels disappears once the question is posed in terms of least-cost planning objectives. As Nadel observed:

> If demand-side resources are to play a major role in meeting future electricity needs, then programs will need to reach a substantial proportion of targeted customers and will need to have a significant impact on the electricity consumption of the customers that are reached.[28]

Since the goal of least-cost planning is to maximize the penetration of all cost-effective measures:

> obviously, to maximize market penetration intensive personal contact marketing and the offer of free measures must be combined. While this combination is the most expensive, it may be the best choice if very high levels of market penetration and energy savings are desired.[29]

As Berry concludes:

---

[28] Id., p. 181.

[29] Berry, L. The Market Penetration of Energy Efficiency Programs. Oak Ridge National Laboratory; April 1990, p. 40.

Participation rates above 50% tend to occur only when all factors are favorable to producing them. That is, they are most likely to occur in highly convenient programs, offering free services and direct installation, which are not supply-constrained, and which are marketed by trusted sponsors through direct personal contact with customers. Id. at 66.

The amount of participation is usually constrained more by the supply of services (i.e., the resources committed to programs) than by the demand for them. Thus, the maximum rates observed may be more relevant to choosing planning assumptions than the average rates. When there is strong enough motivation (and a sufficient commitment of resources) to acquire energy-efficiency resources, participation levels above 50% can probably be obtained for most program types and for most customer groups and communities. Id. at 66-67.

She adds:

market penetration rates above 80% will not be achieved with a business-as-usual approach or with the level of resources typically devoted to programs. Free, direct installation programs that are heavily marketed may sometimes achieve this level of market penetration. Most utilities do not, however, offer such aggressive and expensive programs. .... A realistic view of the evidence suggests, however, that penetration rates above 80% will not occur

> without dramatic changes in typical approaches to the promotion of energy-efficiency programs. Id.

Q: Doesn't such an aggressive approach risk paying too much for DSM savings?

A: It is certainly possible that high penetration could be achieved in some customer segments, market types, or efficiency measures with less than full utility funding. TECo has not determined where this might be possible. The Company will not be able to determine the "optimal" incentive until it finds what works at higher levels. Past utility experience supports the conclusion that setting incentives too low entails more risk than paying too much.

It is important to remember that increasing the fraction that utilities pay for measure costs will not raise the costs of the <u>measures</u> and will reduce the costs of programs under the total-resource perspective. As long as uneconomical measures are eliminated at the screening stage of program planning and the diagnostic stage of implementation, raising utility funding of measure costs is almost certain to increase societal net benefits. Higher incentives will serve only to raise customer participation and measure penetration.

The worst that will happen if incentives are set higher than necessary is that these additional savings cost as much as those that would be achieved with lower incentives. More likely, the fixed costs of marketing and administering programs will be spread over more savings with full utility funding of measure costs. This will tend to increase the net benefits of the program under the total resource cost test.

Q: What evidence supports this claim?

A: There is mounting evidence indicating that full funding lowers the cost of electricity saved by DSM programs to society. Berry reported:

> in some cases, paying 100% of the energy-efficiency measure costs reduces the other program costs enough to make the total cost per kWh saved less than it would be at lower incentive levels. An experiment conducted by NMPC [Niagara Mohawk involving water-heating measures], ... market penetration was five times higher for the free offer and total costs per participant were less. ... Because more penetration was achieved at less costs, savings due to the free offer were ten times higher, at a per kWh cost that was nearly five times less, than consumption reductions from the shared savings offer. (Laim, Miedema, and Clayton 1989) Condelli, et al. (1984) supported the same general point in their report on an insulation program for low-income housing in which promotional and advertising

> costs were greater in absolute terms than the costs for free, direct installation of the measure would have been. Berry, op. cit., pp. 37-38.

Elsewhere, Berry pointed out that "administrative costs per kWh saved are likely to be higher for information-only programs than for programs that pay the full cost of installing measures."[30] She observed that the costs of delivering programs:

> are likely to be about the same [per participant] regardless of the number of measures installed at a particular time in one building. ... Thus, it will be more cost-effective in terms of total resource cost to install everything at one time than it would to be to make several separate installations. The concept of 'lost opportunities' for energy-efficient new construction is based, in part, on this principle. Id. at 21.

b. Other elements of program design

Q: What are the other aspects of comprehensive program design contained in the collaborative utility plans?

---

[30]Berry, L., The Administrative Costs of Energy Conservation Programs. Oak Ridge National Laboratory; November 1989, p. 3.

A: Other features of collaborative programs are summarized for four utilities in Exhibit __PLC-9. These programs follow the following general principles:

- Target program delivery strategies and marketing approaches according to the decision-makers and types of investments involved. Depending on the program, utilities should direct program incentives to utility customers, equipment dealers, architects, engineers, or building developers. Separate marketing and delivery is needed to influence investment decisions in new construction, remodeling/renovation, replacement, and retrofit. Nadel, Lessons Learned, op. cit., p. 186.

- Personal marketing is critical. The prime marketing mechanism for all programs should be personal contacts between utility field representatives and target audiences such as large customers (lighting rebates), HVAC dealers and contractors (HVAC rebates), and architects, engineers and developers (storage cooling and new construction). These personal contacts should strive to develop a regular working relationship with the target audience (e.g., periodic contacts, with the same staff person contacting a particular individual each time). Experience by many utilities, including several side-by-side experiments, shows that personal contact consistently results in higher participation rates than reliance on direct mail, bill stuffers, and other traditional mass-marketing approaches.[31]

- Avoid paying for "naturally-occurring" savings by maintaining high minimum efficiency thresholds. The higher the minimum efficiency

---

[31]For example, NYSEG offered energy audits to two carefully-matched groups of commercial/industrial customers. One group was personally contacted, the other group received a phone call to identify the key decision-maker followed by a direct-mail solicitation to this person. Participation rates averaged 37% for the personal contact group and 9% for the phone/mail group. Xenergy, Inc., Final Report, Commercial Audit Pilot, Burlington, Mass. Likewise, Niagara Mohawk Power Corp. conducted a similar experiment with lighting rebates. Response to the personal solicitation was substantially higher (21%) than it was to the mail solicitation (3%). Clinton, J. and Goett, A., "High-Efficiency Fluorescent Lighting Program: An Experiment with Marketing Techniques to Reach Commercial and Small Industrial Customers" Energy Conservation Program Evaluation: Conservation and Resource Management. Argonne National Laboratory; Argonne, Ill.: August 1989.

criteria utilities set for program eligibility, the more net savings each program dollar buys, assuming equipment complying with minimum standards is widely available. Utilities often see dramatic proof of this principle.[32] This is the best solution for avoiding free riders.

- Encourage measures that improve the efficiency of the overall system, not just equipment efficiency improvements. In many cases, the savings available from improving the overall design of a lighting or HVAC system (e.g., improved sizing, controls, and system layout) exceed the savings from small efficiency improvements in specific components (e.g., lamps, air-conditioners).

- Keep the mechanics of program participation as simple as possible for the customer. The more complex programs appear to customers, the

---

[32]For example, PEPCO found out that, after the Company's response to a phone inquiry, local Sears stores immediately adjusted their appliance inventory in accordance with the minimum performance requirements of PEPCO's air-conditioner rebate program. Personal communication, John Plunkett with Edward Mayberry, PEPCO, January 4, 1990.

lower participation will be. Make it easy for customers to participate, particularly by minimizing complex calculations and paperwork. For example, when a customer requests payment, he should not have to list details on individual measures, but should just refer to the original application number or submit a carbon copy of the original application with a small box at the bottom containing any needed post-installation information. The collaborative programs generally involve a minimum of unnecessary application and verification paperwork.

- Provide the right amount of technical assistance to customers free of charge. Energy audits should serve as the point of entry to utility efficiency programs and should therefore be marketed aggressively. The sophistication of technical support should vary according to the size and complexity of customers. Small customers generally do not need instrumented, computerized diagnosis provided by a professional engineer; a prescriptive approach should work with a walkthrough audit. On the other hand, such a simple approach will not work with large customers, who demand an experienced professional knowledgeable in specific applications before they agree to major efficiency improvements, no matter who bears the cost. To maximize participation and savings in new construction programs, utilities must also provide computerized analysis and pay for outside design assistance.

III. TECO HAS NOT ESTABLISHED THE NEED FOR POLK UNIT ONE BECAUSE IT HAS NOT EXHAUSTED LEAST-COST DEMAND-SIDE ALTERNATIVES TO POLK UNIT ONE

Q: Summarize your findings on TECo's demand-side plans as they relate to the need for Polk Unit One.

A: Thus far, TECo has under-invested in energy-saving demand-side resources. While the Company has continued its pursuit of peak demand savings with extensive load management efforts, it has failed to target economical energy-efficiency resources adequately. The scope, scale, and pace of TECo's planned acquisitions of demand-side resources are inadequate given the magnitude, composition, and timing of its supply commitments. As shown in Exhibit __PLC-3, TECo's present commitments represent only 277 MW and 208 GWh from energy-efficiency resources through the year 1996. They account for 16% of projected peak demand growth, and 4% of energy sales growth, through 1996.

Such small savings come as no surprise, given the relatively low levels of expenditures TECo plans for energy-saving DSM. Of the approximately $1.3 million TECo currently plans to spend per month on DSM programs, almost 80% is budgeted for load management efforts.[33]

In sharp contrast to TECo's limited commitment to energy-efficiency resources, leading utilities with the most ambitious DSM programs -- those designed in collaboration with non-utility parties -- plan to meet significantly higher proportions of their load growth with DSM. The reasons for such higher DSM targets include unbiased and comprehensive DSM program planning and much stronger utility financial commitments. I show in Section IV that commensurate commitments by TECo would reasonably be expected to produce an additional 96 MW and 512 GWh by the year 1996.

Q: How does TECo's failure to pursue additional energy-efficiency resources relate to its application for a Determination of Need for Polk Unit One?

A: Because of the Company's inadequate approach and commitment to DSM, TECo has failed to establish that DSM cannot substitute more cost-effectively for some or all of the energy and capacity from Polk Unit One. TECo's resource plans omit energy-saving demand-side resources that could be cost-

---

[33]Based on data provided in Exhibit GJK-2, Schedule C-2 of the testimony of Company witness Kordecki in Docket No. 910002-EG.

effective compared to Polk Unit One under the total resource cost test. Like leading utilities, TECo should fully develop and pursue all cost-effective alternatives to the supply resources contained in its benchmark plan. Its resource plan should include and be premised on timely acquisition of all cost-effective resources. Every kW and kWh of cost-effective demand-side resources that TECo could add over Polk Unit One's life represents a kW or kWh not needed from Polk Unit One, at least on the current schedule.

Q: In your opinion, what shortcomings in TECo's demand-side planning are responsible for its under-investment in DSM compared to Polk Unit One?

A: TECo's weak demand-side planning has prevented the Company from pursuing energy-saving demand-side resources to their cost-effective limits before deciding to pursue Polk Unit One. This weakness is attributable to deficiencies and omissions in the Company's approach to program design and implementation. More specifically:

1. The Company's reliance on the RIM test for economic screening leads to the rejection of economical savings

opportunities. TECo's economic screening is further biased by the Company's failure to incorporate estimates of avoided T&D costs and environmental externalities in evaluations of DSM options.

2. TECo fails to target DSM market sectors comprehensively. The Company omits essential sectors, end-uses, and measures.

3. TECo's existing programs inadequately address market barriers. Customer incentives are too low, direct installation programs are non-existent, and programs are fragmented.

4. TECo is not sufficiently ambitious. The Company has set its participation goals far too low.

5. TECo overemphasizes load management to the detriment of conservation. Load management may be developed in place of

cost-effective energy conservation, thus limiting the cost-effective energy savings TECo can achieve in the long run.

A. TECo's economic screening tests are biased

Q: Why is TECO's economic evaluation of DSM biased?

A: The Company's screening of DSM measures and programs relies primarily on the RIM or no-losers test to evaluate DSM cost-effectiveness. As discussed above in Section II.b, DSM that is economical under the total resource cost test may be rejected under the RIM test. In addition, the Company inexplicably assumes that demand-side options do not avoid T&D investments or environmental externalities of generation.[34]

Q: How do you know that TECo uses the RIM to restrict demand-side investments?

A: According to Company witness Kordecki:

---

[34] The Company also underestimates costs avoided by DSM, and therefore the magnitude of economical savings, by not estimating the cost savings associated with DSM as a Clean Air Act compliance strategy. Specifically, the Company does not allow for additional allowances due to DSM activities prior to 1995, or reduced requirements for allowances thereafter; nor does it model strategies that include intensified DSM as an alternative to scrubbing or fuel switching. See generally the Polk Unit One Need Determination Study, pp. 20-24.

> The company uses all the tests to examine potential programs, but relies primarily on the Participant Test for market potential <u>and the Rate Impact Test for actual cost-benefit analysis</u>.[35] [emphasis added]

Q: What indication do you have that the Company assumes no T&D savings from DSM investments?

A: In its evaluation of DSM programs in the Conservation Plan, the Company sets the value of avoided T&D to zero for all cost-effectiveness screening. Unfortunately, the Company does not offer any explanation for this action.

B. TECo's programs are not comprehensive

Q: In what ways are TECo's programs not comprehensive?

A: Certain fundamental omissions keep TECo's program portfolio from being comprehensive, ignoring DSM resources that can provide significant sources of savings. TECo's omissions include:

- Customer sectors, in particular, lost opportunity sectors and low-income customers;

---

[35] Direct testimony of Gerard J. Kordecki, p. 9.

- end-uses, such as residential lighting and chillers; and

- measures, most notably fuel-switching.

1. **Missing customer sectors**

a. **Lost opportunities**

Q: Summarize your findings on TECo's failure to pursue lost-opportunity resources.

A: TECo's current resource plan lacks an effective strategy for obtaining lost-opportunity measures and thus systematically excludes cost-effective demand-side resources from its resource plan. By failing to move vigorously to achieve all cost-effective lost-opportunity resources, TECo increases the total costs of providing electric service. Eventually the Company might end up acquiring <u>some</u> of these savings as more expensive retrofits. The rest of the cost-effective savings that TECo misses will be irretrievably lost; the Company will have to make up for these lost opportunities with more costly supply.

Q: How should TECo pursue lost-opportunity resources?

A: TECo should target programs to affect appliance replacement, new construction in the commercial and residential sector, commercial remodeling/renovation, and commercial and industrial equipment replacement. TECo should offer incentives for equipment whose efficiency exceeds current standards (either of law or practice). Section IV, below, summarizes the types of programs TECo should implement for each conservation market sector.

Q: What sources of lost-opportunity savings is TECo bypassing?

A: Unfortunately, TECo has so far ignored the lost opportunities presented by residential new construction and appliance and water heater replacement, and by commercial building design, refrigeration and HVAC.

Q: Does TECo's plan contain any programs that target lost-opportunity resources?

A: Yes. TECo's Conservation Value Program addresses C/I new construction and equipment replacement, and the Residential Heating and Cooling program seeks to affect the efficiency of HVAC equipment being replaced.

Q: Is the Conservation Value program likely to maximize the cost-effective savings TECo can obtain from new construction and equipment replacement?

A: No. The Conservation Value program has two major flaws. First, it discourages the adoption of energy-saving measures by penalizing measures that save energy in the off-peak hours.[36] Second, it encourages cream-skimming and accentuates free-ridership by capping financial incentives. Customers will opt not to pursue measures that are more costly, more difficult to implement, or perceived as risky. They will instead implement only the cheapest, simplest, and most predictable measures. Since these are the measures most likely to be implemented without a program, TECo is paying for what would have been done anyway.

Q: Is the Heating and Cooling program likely to be effective?

A: No. The effectiveness of the Heating and Cooling program will suffer because equipment eligibility thresholds are too low. The minimum qualifying seasonal energy-efficiency ratio (SEER) is 10 for split-system heat pumps and central air-conditioners. Yet by January 1st, 1992, it will be illegal to manufacture split-system heat pumps and

---

[36]For example, a measure that saves 1,260 kWh during summer peak hours would be eligible for a $200 rebate. However, if the same measure also saves approximately 2,500 kWh during off-peak hours, it would not be eligible for any rebate.

air-conditioners with an SEER of less than 10 (See 10 CFR CH. II, Part 430, Subpart C, §430:32). Thus, TECo will effectively be rewarding local merchants for selling what the law already requires. Instead, the Company should try to influence customers and dealers to beat the standards and purchase high-efficiency equipment.[37]

b. Lack of a program for low-income customers

Q: Does TECo offer any programs specifically designed for low-income customers?

A: No.

Q: Are low-income customers likely to participate in TECo's existing programs?

A: Eligible low-income customers are not likely to be able to participate in TECo's existing programs. Low-income households offer a classic example of

---

[37] As indicated in its February 12, 1990 Conservation Plan, the Company was taking a small step toward beating the standards by proposing to offer slightly larger dealer incentives for "super" units with SEERs of 11. Inexplicably, the Company is now planning to offer a flat rebate regardless of unit size for all units with SEER 10 or greater. Letter from Howard T. Bryant, TECo, to Terry Black, Pace University Energy Project, August 26, 1991.

To maximize program savings, TECo should offer progressively larger incentives for efficiency levels beyond SEER 10. Moreover, these incentives should be structured to flow-through to the retail price, to reduce the efficiency premium faced by consumers.

how market barriers can interact to retard efficiency investment. They have virtually no access to capital on any terms. Residents rarely own their own homes, and thus have little motivation to invest even if they had the means. Even with access to enough capital to finance efficiency investments and the incentive to invest it, the specific financial risks of parting with the funds would pose a high hurdle. Finally, low-income customers are less able to obtain and act on the information needed to choose between efficiency options. Those customers who do not speak English (or do not speak it well) will not benefit from the educational component of an audit.

This combination of forces is strong enough to justify direct utility investment in the dwellings occupied by low-income customers.[38]

Q: Why should TECo offer a program that meets the needs of its low-income customers?

A: Like all other customers, low-income customers must bear the cost of TECo's DSM programs. However,

---

[38]Various regulators have required utilities to target low-income customers with efficiency investments, including Wisconsin (Findings of Fact and Order in Docket 05-UI-12, April 20, 1982, at 13-15), Vermont (Docket 5270, Vol. III, pp. 60-62, and 158-159), and New York (Case 89-M-124, Order of June 29, 1989).

unlike other customers, low-income customers are effectively excluded from participation in any of TECo's existing programs. This raises problems of equity. In addition, helping to reduce low-income customers' consumption will help lower their bills. This in turn is likely to help lower TECo's uncollectible accounts.

2. Missing end-uses

Q: Which end-uses do TECo's programs fail to address?

A: TECo fails to offer efficiency measures for the following end-uses in the retrofit, replacement, or new construction market sectors:

Residential sector

- refrigerators and freezers;
- water heating;
- lighting;
- clothes washers and dryers, dishwashers, and electric ranges.

C/I Sector[39]

- HVAC equipment;

---

[39] In theory, all C/I end-uses can be targeted with the Conservation Value program. However, as discussed above, the incentive structure for this program effectively excludes adoption of all energy-saving DSM measures.

- chillers;[40]
- motors;
- commercial and industrial refrigeration.

Thus, TECo's current resource plan ignores numerous efficiency options available for many end-uses across all customer market segments.

3. Missing measures

Q: For the end-uses addressed in TECo's plan, are there efficiency measures missing from the Company's programs?

A: Yes. TECo has omitted measures that can offer substantial and long-lasting savings, including:

- thermal integrity and equipment efficiency improvements in new residential and commercial construction;

- residential and C/I thermal integrity retrofit improvements;

---

[40]Steve Nadel notes that "chillers account for approximately half of all air-conditioning capacity in the commercial sector." Lessons Learned, op. cit., p. 58.

- fuel-switching measures.

Q: Why should TECo include fuel switching in its DSM program analysis?

A: Depending on the costs of selecting or converting to the alternative fuel and the relative end-use efficiencies, fuel-switching can be quite cost-effective.[41] In addition, the aggregate electric savings due to fuel switching can be substantial.

Q: Has fuel-switching been found to be cost-effective in other studies or adopted by utilities as part of their DSM programs?

A: Yes. The cost-effectiveness of fuel-switching has been addressed for various applications and various fuels in the studies I performed for Boston Gas in Mass. DPU 89-239 and DPU 90-261A,[42] in the work of several Vermont utilities, in the Bonneville Power Administration Resource Plan,[43] and in a Lawrence

---

[41]The costs of fuel-switching vary with the application (e.g., scale, building layout), the building's status (e.g., new construction, retrofit, major renovation), and the length of gas service required, if any.

[42]Chernick, P., et al., Analysis of Fuel Substitution as an Electric Conservation Option. December 1989.

[43]Bonneville Power Administration, 1990 Resource Program Technical Report. July 1990.

Berkeley Lab study for Michigan,[44] among others. All of these studies indicate that alternative fuels can be less expensive than electricity for at least some applications of each end-use considered. Fuel switching for at least some end uses has been incorporated in the DSM programs of Green Mountain Power, Burlington (VT) Electric Department, New York State Electric and Gas, Long Island Lighting, Consumers Power, Madison Gas and Electric, and Consolidated Edison, to name a few. Most of these studies and programs involve fuel-switching to gas, but the Vermont utilities also determined that conversion of residential space and water heating to oil and propane will often be cost-effective.[45] Thus, fuel-switching is not a particularly exotic or obscure DSM option. The technology is also well-developed.

C. Inadequacies of TECo's existing programs

Q: What are the major inadequacies of TECo's existing

---

[44]Krause, F. et al., Analysis of Michigan's Demand-Side Electricity Resources in the Residential Sector. MERRA Research Corporation. April 1988.

[45]Solar might also be included in this list, especially for water heating. I would generally treat solar as a conservation option, rather than fuel-switching, since it does not require any continuing energy input.

programs?

A: TECo's programs are characterized by

- insufficient incentives;
- absence of direct delivery mechanisms; and
- a fragmented treatment of DSM market sectors.

1. **Insufficient incentives**

Q: Are TECo's incentives likely to be effective in combating market barriers?

A: No. TECo's incentives are set too low for acquiring all cost-effective conservation resources. TECo's incentives never cover more than half of measure cost.[46]

Q: Why should TECo pay for more than half of a measure's cost?

A: As discussed above, pervasive and multiple market barriers are strong deterrents to customer investment in efficiency. Utilities have found it necessary to offer incentives of more than 50% of measure cost in order to adequately combat these

[46]The incentive for the Conservation Value program may be an exception. However, TECo does not provide the requisite details on measure costs to determine the fraction of incremental costs covered by incentives.

market barriers. Based on a survey of non-residential efficiency programs, Steve Nadel concludes that:

> Data on the effect of different incentive levels are limited but show that providing free measures results in the highest participation rates. High incentives (greater than 50% of measure costs) appear to promote greater participation than moderate incentives (on the order of 1/3 of measure cost).[47]

Q: How can TECo determine how much to pay for program measures?

A: TECo should start by identifying an efficient mechanism for delivering services in each market. Given that mechanism and the nature of the market barriers in each market, TECo should select a funding level that will achieve essentially all of the achievable potential by the time it is cost-effective and will not significantly increase the costs of program delivery. TECo should not arbitrarily refuse to pay for the full incremental cost, if that is the most effective and efficient means of securing those improvements.

---

[47]Nadel, S., Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers. April 1990, p. 186.

To the extent that some program costs are recovered from participants, the participants should be given the option of having the recovery flow through their bills over a period of time. This may be very important for some customers (such as government agencies) which would have to secure numerous and complicated approvals to put up cash or to sign a loan agreement. It may also be important for customers with cash constraints and may overcome a psychological barrier even for those customers who are not cash-constrained.

2. No direct delivery mechanisms

Q: Does TECo offer programs that directly install efficiency measures?

A: No. All of the Company's conservation programs rely on the customer to install measures and then apply for rebates.

Q: Why should TECo utilize direct delivery mechanisms?

A: There are many barriers to customer action that will be inadequately or inefficiently addressed by information, loans, or rebates. Uncertainty, lack of knowledge, split incentives, lack of time for exploring options, limited retail availability, and aversion to dealing with contractors will not be overcome by partial rebates. In general, the easier the Company makes it for customers to participate and choose cost-effective measures, the more cost-effective savings TECo will acquire.

For some market sectors, TECo should offer direct design and/or installation services.[48] For example, a residential retrofit program should provide for an audit, selection of cost-effective measures, and installation, with as little demand on customer time and budget as possible. This is particularly important for residential and small commercial customers, and may also be significant for larger customers in some segments.

3. TECo's fragmented treatment of DSM market sectors

Q: Substantiate your statement that TECo's demand-side plans are fragmented.

A: TECo makes the mistake of equating individual measures with "programs." Rather than proceed measure by measure in its pursuit of cost-effective conservation savings, TECo should proceed sector by sector, seeking to acquire all cost-effective savings available from a full set of measures

[48] The actual delivery would usually be through a contractor, rather than by TECo employees.

applicable to each customer's facilities. TECo's piecemeal strategies will inevitably raise costs, reduce savings, and delay results.

Q: Which of TECo's programs would you characterize as single-measure programs?

A: All of TECo's rebate programs are single-measure.

Q: What is wrong with the Company's single-measure approach?

A: By pursuing single-measure strategies, TECo passes up opportunities to bundle measures in comprehensive programs. A comprehensive program delivers all the efficiency services that are economical as a package; the single cost of getting an installer to the building is spread across a large number of measures, and no potential cost-effective savings are left "on the table." Bundling measures would lower the overall cost of TECo's DSM portfolio by reducing delivery and administrative costs, while increasing the amount of savings TECo can expect from each customer visit. It may also increase participation: customers are more likely to participate in a program that offers several measures than in a single-measure program.

Unfortunately, TECo does not use this

approach in its programs. For example, the water heater control in TECo's Prime Time Load Management program appears to be completely isolated from other water-heating measures, let alone measures for other end-uses. Before TECo installs a control on an electric water heater, it should determine whether that control is more beneficial than alternatives, such as converting the customer to a gas water heater, installing a water-heating heat pump, or improving efficiency. Even if TECo finds that controlling the water heater is not cost-effective, all the efficiency improvements are still likely to be cost-effective. While TECo has an installer on the premises, it should ensure that the water heater and pipes are wrapped and that efficient showerheads and faucet aerators are installed. With little additional cost, the same installer can screw in a few compact fluorescent light bulbs. Such a comprehensive approach is typical of residential programs designed in collaboration with non-utility parties as shown in Section II.F., above.

D. TECo's DSM portfolio places undue emphasis on peak savings

Q: Why do you believe that TECo's DSM portfolio places undue emphasis on peak savings?

A: A review of TECo's programs suggests that the Company devotes much of its DSM effort to measures that reduce peak, rather than to measures that reduce baseload energy use. This is confirmed by the Company's spending patterns for conservation and load management programs. In addition, an analysis of TECo's MW and GWh savings confirms that TECo's DSM efforts focus on load management and peak savings rather than baseload energy savings.

Q: By what measure did you assess the extent to which TECo's DSM resources are devoted to peak savings?

A: I determined the load factor of TECo's DSM portfolio, calculated as:

GWh saved/(MW saved*8.760).

By 1996, TECo expects its <u>conservation</u> programs to have a collective load factor of 8.6%. Adding in load management savings reduces the overall load factor to 4.9%.

Q: How does this load factor categorize TECo's DSM resources?

A: Just as a power plant's load factor can categorize the plant as a base, intermediate, or peaking resource, so can DSM portfolios be categorized by their load factors. The low load factor of TECo's energy-saving resources reveals that they do not even provide as much peak energy as their avoided peaking unit. In its input data for cost-effectiveness determination, TECo notes that its avoided peaking unit has a capacity factor of 10%.[49] Thus, load management may not fully replace CT capacity, MW for MW.

Q: Is the 8.6% conservation load factor appropriate, given TECo's capacity and energy needs?

A: No. With an 8.6% load factor, TECo's conservation resource acts as a peaking plant. TECo's next avoidable unit, Polk Unit One, is expected to run as a baseload unit. Thus, TECo is investing in a "DSM peaking plant" while at the same time seeking to build a baseload unit.

Q: Why else might TECo want to place more emphasis on acquiring energy savings, rather than peak savings?

A: Kilowatt for kilowatt, efficiency resources are more valuable than load control. Unlike load control, efficiency resources save energy; reduce environmental impact (and hence, costs of control); consistently reduce requirements for the

[49]Conservation Plan, p. 8.

generation, transmission, and distribution capacity; are more durable; and do not involve service degradation. Efficiency resources are particularly valuable because:

- Load control savings will decline as efficiency programs affect equipment stock. As the equipment under control becomes more efficient, savings from controlling or interrupting this equipment will decline.

- Conservation helps avoid expensive baseload combined cycle plants, and load management helps avoid cheaper peaking combustion turbine plants.

E. Unambitious plans

Q: Please explain why you characterize TECo's plans as unambitious.

A: As shown in Exhibit __PLC-10, TECo's own participation figures reveal that the Company has set very low participation goals for its DSM programs. By 1996, the highest participation rates for measure-based programs are 24% for the

Residential Heating and Cooling and C/I Indoor Lighting programs. Participation rates for Residential Ceiling Insulation and C/I Conservation Value are less than 8%. These extremely low participation rates indicate that the Company is not maximizing its DSM resources.

IV. TECO CAN SUBSTANTIALLY INCREASE THE SCOPE AND SCALE OF ITS DEMAND-SIDE INVESTMENT

Q: If TECo corrected the deficiencies in its demand-side planning, could the Company acquire significantly more cost-effective conservation resources?

A: Yes. As I show below, TECo could acquire substantially larger savings by expanding the scope and scale of its demand-side efforts to levels that are comparable to those attained in collaboratively-designed plans. From my comparative review of TECo's current plans and those of utilities with collaboratively-designed DSM programs, I find that TECo could reasonably expect to acquire at least an additional 96 MW and 512 GWh in annual savings from cost-effective DSM by the year 1996. These additional savings will only be achievable if TECo adopts the market-based, comprehensive approach to demand-side planning and acquisition in use in collaboratively-designed resource acquisition strategies.

Q: Can you categorize the efficiency resources missing from TECo's current resource plans which the Company should pursue now?

A: Based on the portfolios of programs being sponsored by other utilities with collaborative-designed programs, TECo should develop and implement programs that pursue all cost-effective efficiency savings from the following market sectors:[50]

Non-residential customers

- Commercial new construction
- Industrial new construction/expansion
- Commercial/industrial renovation/remodeling
- Non-profit/institutional/government custom retrofit
- More aggressive and comprehensive commercial lighting
- Direct investment for small commercial customers, focusing on all cost-effective lighting retrofits
- Commercial/industrial equipment replacement

Residential

- Residential new construction
- Residential comprehensive retrofit

---

[50]TECo's programs may already serve a few segments of these market sectors. However, the Company's program strategy fails to target each market sector with appropriate delivery mechanisms.

High-use (central heating/cooling)
Moderate use (water heating)
General (lighting)

- Comprehensive retrofits for low-income customers
- Point of sale lighting
- Expanded incentives for energy-efficient appliance replacement (including room AC, hot-water heaters)
- Point of sale information and incentives for other appliances (e.g., refrigerators)
- Manufacturer incentives for super-efficient appliances

Q: How does the program scope that you recommend differ from TECo's approach to program targeting?

A: The program concepts I sketch are comprehensive in terms of the market segments targeted, end-uses covered, the strategies employed, and their inter-relationship to one another within overall customer groups. By contrast, TECo's approach inappropriately treats an end-use or technology separately, generalizing the measure to an entire customer group.

Q: How much more electricity should TECo be expected to save by investing in comprehensive efficiency resources?

A: A precise answer to this question will have to wait until TECo gains experience with comprehensive programs of the scope described above. Nevertheless, it is possible to extrapolate in general terms from the plans of utilities with the best and most comprehensive program designs -- that is, the plans of the collaborative utilities discussed in Section II.F. above. I have used such an approach to derive a rough but reasonable estimate of the additional demand-side resources that TECo should be expected to acquire if it follows the lead of utilities with aggressive and comprehensive demand-side plans.

Q: How much additional demand-side resources do you estimate that TECo should be able to obtain?

A: Using the plans of utilities with collaboratively-designed programs as a guide, I estimate that TECo should be able to acquire an additional 96 MW of cost-effective demand savings from further <u>conservation</u> investment by 1995/96. I present these projections in Exhibit __PLC-11. Including the Company's current plans for conservation and load management, TECo's total demand-side savings should be 578 MW by the year 1995/96. These totals represent 17% of 1995/96 retail system peak demand. By comparison, the Company's current plans account for 14% of 1995/96 peak load.

Q: Are there significant energy savings associated with the higher peak-demand reductions you project?

A: Yes, there are. By the year 1996, my demand-side resource projections include 720 GWh of energy savings, representing 4.6% of total retail sales. These energy savings levels would be more than three times those included in TECo's current plans, which account for only 1.3% of total energy sales.

Q: Would the savings you estimate influence the timing of Polk Unit One?

A: By incorporating my estimate of additional peak demand savings in the loads and resource balance projected for TECo, it is clear that the additional DSM would have a noticeable impact on the need for Polk Unit One to meet projected peak demand. This is shown in Exhibit __PLC-12, which restates the Company's capacity and load position originally shown in Exhibit __PLC-2.

With the additional demand savings, the first 150 MW of Polk Unit One installed in 1995/96 is no longer required to maintain a 20% reserve margin. Instead, the Company would require only 75 MW of capacity in 1996/97.

Q: How would the additional energy savings you project influence the economics of combined-cycle technology for the Polk Unit One project?

A: I have not performed the rigorous capacity-expansion analysis that would be required to answer this question with any real precision. Nonetheless, I believe that the substantial increase in energy savings would reduce the fuel-cost savings associated with the Polk Unit One project by reducing the marginal energy costs on TECo's system. This effect may be large enough to either substitute a 75 MW CT for the 220 MW combined-cycle capacity, or to delay the addition of the heat recovery steam generator and coal gasifier beyond 1996/97.

Q: How did you estimate future energy and peak demand savings from a comprehensive portfolio of TECo DSM programs shown in Exhibit __PLC-11?

A: First, I projected that annual acquisitions of demand-side energy resources would equal specific percentages of projected annual sales growth. As explained below, I chose these percentages on the basis of DSM savings plans of six utilities with collaboratively-designed DSM portfolios (for which I was able to obtain class-specific energy-savings projections). I multiplied these annual percentages by TECo's projected annual sales growth. The sum of these annual DSM energy acquisitions leads to cumulative energy resource acquisitions from DSM after 1991. To arrive at the total energy savings to be expected each year from all TECo's DSM programs, I then added these annual energy acquisitions to the 1991 DSM energy savings projected by TECo in its NDS.[51]

Second, to project peak demand savings generated by intensifying TECo's DSM portfolio, I applied appropriate DSM capacity factors to the additional cumulative DSM energy resource acquisitions I estimated as explained above.

Q: How did you arrive at the annual percentages you applied to TECo to determine incremental annual DSM energy savings?

A: I relied on the projected energy savings from residential and non-residential customers shown for utilities with collaboratively-designed programs in

[51]Total savings are for conservation resources only. Thus, all figures exclude TECo's projections for load management.

Exhibit __PLC-6. For residential programs, these plans indicate a range of DSM energy savings of between 8% and 72% of cumulative sales growth. For non-residential customers, Exhibit __PLC-6 suggests that utilities with collaboratively-designed programs plan to save between 31% and 81% of cumulative growth in sectoral energy sales. From these plans, I projected that mature TECo DSM programs could generate energy savings equal to 35% of new (post-1991) growth in total retail energy sales.[52] I allowed three years for program ramp-up by starting TECo's DSM energy savings at a rate of 25% of projected annual sales increases in 1992. I increased this fraction to 30% in 1993 and to 35% from 1994 to 2000. The result in each year is the

---

[52]The simple mean of these relative shares is 35% for residential programs and 50% for non-residential programs for the six utilities' residential programs for which sufficient information was available. Weighted according to projected energy sales for TECo's residential and non-residential classes, the savings amount to 43% of projected energy sales growth.

Although TECo's sales growth is 25% more than the growth expected for these collaborative utilities, I would expect absolute savings to be less than those estimated using the 43% figure. Savings from retrofits and routine replacement of existing customer equipment may account for a large portion of total savings achieved by collaboratively-designed programs. To account for this, I assumed that savings due to load growth account for 20% of total savings, and therefore a 25% increase in load growth will increase total savings by only 6%. To reflect this relationship between load growth and total savings growth, I reduced the 43% figure to 35%.

incremental energy savings that TECo should be able to obtain with appropriately comprehensive programs.

Q: How did you arrive at the load factors you used to translate additional energy savings into additional peak load reductions?

A: I developed the DSM load factor to apply to the additional DSM energy savings on the basis of the DSM plans of six utilities with collaboratively-designed programs for which I was able to obtain projections of energy and demand savings.[53] I developed these load factors by calculating the weighted average DSM load factor from the DSM plans of BECO, EUA, NEES, NYSEG, NU, and UI.[54] The average is 41%; this compares to 8% for TECo's "conservation" programs by 1996.

I then adjusted the average load factor by adding 20 percentage points to the calculated average load factor. This adjustment is intended

---

[53] One of the utilities on which I relied for projecting energy shares did not have peak-savings projections.

[54] The weighting was accomplished by summing the four utilities' cumulative energy savings from DSM and dividing by the sum of their respective peak demand savings, which are shown in Exhibit __PLC-6. This quantity was multiplied by 1,000 and divided by 8,766 hours/year.

to reflect the fact that, while the subject utilities include load control programs in their DSM plans, the purpose of the load factor is to estimate peak demand savings for TECo resulting from <u>additional</u> energy-saving DSM -- i.e., in addition to the load control already contained in the Company's Conservation Plan. Thus, I applied a 61% load factor to my estimate of additional energy savings to yield additional peak savings.

V. CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

Q: Summarize your conclusions with respect to TECo's resource planning and the need for Polk Unit One capacity.

A: While TECo has identified a need for additional resources towards the end of this decade, it has not established that Polk Unit One is the best alternative for meeting this need. On the contrary, TECo has failed to properly identify, develop, evaluate, and pursue significant opportunities for cost-effective demand-side savings. Every kilowatt and every kilowatt-hour of cost-effective capacity and energy from such alternatives that TECo has failed to include in its resource plan constitutes Polk Unit One capacity and energy that TECo does not need, at least on the current schedule.

Q: If TECo needs capacity and energy resources by the latter half of the decade, why should the Commission conclude that the Polk Unit One project is not needed to meet these requirements?

A: To conclude that Polk Unit One is needed on the current schedule, the Commission must find that cost-effective alternative resources, including demand-side management, cannot provide enough energy or capacity to affect the optimal timing or type of development at Polk Unit One.

No such finding is supported by the evidence presented by TECo. My testimony shows that TECo has not identified the amount of cost-effective DSM it could obtain in place of some or all of the Polk Unit One investment. The Commission certainly cannot find that TECo's application is premised on the exhaustive pursuit of all cost-effective alternatives to Polk Unit One.

The inescapable conclusion is that TECo has not established the need for building Polk Unit One; nor has the Company established that Polk Unit One is the least-cost resource available for meeting future capacity and energy needs.

Q: Summarize your conclusions with regard to TECo's demand-side resource planning.

A: TECo's DSM planning suffers from several major deficiencies, including:

- TECo is not comprehensively assessing, targeting, and pursuing energy-efficiency resources. TECo's piecemeal pursuit of savings will unnecessarily raise costs and reduce savings achieved from demand-side resources.

- TECo is neglecting large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, TECo loses them. Such lost-opportunity resources arise when new buildings and facilities are constructed, when existing facilities are renovated or rehabilitated, and when customers replace existing equipment that reaches the end of its economic life. To make matters worse, TECo's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- TECo's programs are not strong enough to overcome the pervasive market barriers that obstruct customer investment in cost-effective efficiency measures. Incentives are not high enough, and programs do not address many important barriers.

Q: Summarize your conclusions with regard to the reforms needed in TECo's demand-side resource planning.

A: TECo's approach to DSM planning must be improved if the Company's resource planning is to be truly integrated, and if the Commission expects TECo to deploy a least-cost resource portfolio. Correcting this approach should enable TECo to meet about 35% of its energy sales growth with additional demand-side acquisitions. This translates into additional demand-side savings of about 96 MW and 512 GWh through the year 1995/96.

TECo should re-orient its demand-side planning toward comprehensive investment in efficiency savings in all market sectors, and abandon its narrow focus on individual measures and end-uses. In pursuing savings potential identified through this comprehensive approach, TECo should devise demand-side strategies to eliminate the myriad market barriers obstructing customer investment in cost-effective energy-efficiency measures. In deciding how to proceed toward achieving the cost-effective demand-side savings identified under such improved planning, TECo should pursue all cost-effective lost-opportunity resources as quickly as administratively feasible.

B. Recommendations

Q: What are your recommendations with regard to TECo's petition for a Determination of Need?

A: I would recommend that the Commission decline to approve the Company's proposal to build Polk Unit One until the utility demonstrates (1) that it has undertaken to implement all economic energy efficiency and load management that could displace new power plants and (2) that the proposed combustion turbine and combined-cycle components of Polk Unit One are still the least cost supply option available to meet any remaining requirements. Regardless of the Commission's ultimate decision on TECo's application, I recommend that the Commission direct the Company to improve its planning and acquisition of demand-side resources before it commits to the construction of the Polk Unit One project.

Q: Why should the Commission require TECo to reform its integrated resource planning before acquiring the Polk Unit One project?

A: Unless TECo reforms its planning efforts, the demand-side resources generated by its approach to program design will be unnecessarily small, slow, and expensive. Consequently, TECo should be directed to pursue and acquire demand-side savings much more aggressively, much more comprehensively, and on a much larger scale, before the Commission allows the Company to build Polk Unit One or any other major supply option.

Q: Please summarize how the Commission should require TECo to proceed to plan for and acquire demand-side resources.

A: The Commission should direct TECo to immediately initiate efficiency investments in accord with the principles set forth above. These efforts should be comprehensive, as that term is defined and illustrated above. In particular, TECo should immediately target lost opportunities arising in new construction and in equipment replacement.

Specific details of how TECo should accomplish these objectives are beyond the scope of this testimony. The responsibility for devising and executing these actions rests with the Company; however, it would be to TECo's advantage to enlist the expertise and creativity of other parties.

Q: Which fundamental principles of demand-side resource planning and acquisition should the Commission direct TECo to follow in the future?

A: I strongly urge the Commission to direct TECo to incorporate the following basic elements in its future demand-side planning and acquisition, all of which are inherent in the DSM program plans of other utilities engaged in truly collaborative processes:

- the explicit pursuit of all cost-effective demand-side resources;

- a commitment to a comprehensive approach to this objective, including a full complement of marketing, delivery, and customer incentive strategies designed to achieve installation of all cost-effective measures for customers in all significant market sectors;

- a high priority on aggressive investment in lost-opportunity resources presented in new construction, remodeling/renovation of existing facilities, and replacement of existing equipment; and

- a willingness to pay what is necessary to maximize achievement of cost-effective savings, including full funding for and direct investment in hard-to-reach and especially valuable efficiency resources (e.g., payment of full incremental costs of lost-opportunity measures, and fully-funded direct investment for small commercial and residential customers).

Q: What action can the Commission take on the Company's petition to emphasize the need for reforms?

A: The Commission understands better than I the options at its disposal. Depending on the statutory and regulatory structure, and TECo's traditional responsiveness to Commission directives, there may be several ways in which the Commission produce its desired result. However, I recommend that the Commission act to ensure that construction of the Polk Unit One plant does not start until TECo has demonstrated that (1) it is aggressively pursuing all cost-effective efficiency opportunities and (2) the plant is required and cost-effective even with the development of all achievable cost-effective efficiency resources.[55]

One option is for the Commission to reject TECo's petition for a Determination of Need for the Polk Unit One project, while indicating that the plant would be viewed more favorably once TECo can meet the conditions listed above. In the meantime, the Company might be directed to take all necessary steps to authorize and permit the Polk Unit One site.

Alternatively, the Commission could issue a provisional determination for all or part of the

---

[55] I will assume for the purposes of this discussion that the Commission finds that Polk Unit One will be an appropriate choice for baseload capacity when that is needed. I have not examined TECo's supply alternatives.

Polk Unit One project, conditioned on the Company meeting (in a future proceeding) the two requirements listed above.

In addition, the Commission could signal its intent to link Polk Unit One prudence determinations to the Company's progress in improving its demand-side planning and acquisition procedures.

Any of these approaches would allow adequate time for vigorous pursuit of the demand-side resources TECo has not yet developed before committing to the Polk Unit One project, while securing the option of developing the plant, if and when that action is appropriate. Appropriately structured, any of these options can serve as notice to the Company that all cost-effective demand-side resources must be acquired before it commits to the acquisition of Polk Unit One capacity.

Q: Are you recommending that the Commission direct TECo to acquire additional savings equivalent to the levels you have estimated as attainable by the Company?

A: No. Although they may be appropriate goals, my estimates are illustrative of the magnitude of savings available if TECo developed comprehensive acquisition strategies comparable to those adopted by other leading U.S. utilities. The true extent of achievable demand-side savings can only be determined as part of an extensive effort to develop DSM opportunities in TECo's service area.

Q: Is it reasonable and prudent for TECo to plan for the contingency that it will need additional power in 1995/96 or beyond?

A: Yes. In addition to developing contingency plans for adding resources to the system in 1995/96, TECo should also be developing strategies for minimizing the lead-time necessary to acquire resources when they are required or become cost-effective. However, <u>planning</u> to develop the resource is not the same as <u>committing to acquisition</u> of the resource. The acquisition decision does not need to be made immediately, as long as efforts are made to develop the option to acquire.

At the same time, TECo should be planning <u>and</u> acquiring all cost-effective demand-side resources.[56] With additional demand-side resources

---

[56]DSM is cost-effective if it is less expensive than system avoided cost, including avoided generation capacity, energy, T&D, losses, and environmental costs. DSM can be cost-effective, even if it is more expensive per kWh than Polk Unit One, since the DSM resource avoids

in its resource portfolio, the Company may find that its deadline for making the decision to acquire additional capacity can be delayed beyond that originally anticipated or that power requirements can be met at lower cost with alternative supply options.

Q: When should the decision to acquire a supply resource be made?

A: If all steps are taken to permit and authorize the site, the decision essentially needs to be made only as far in advance as required by construction leadtime. While it may be reasonable to commit at an earlier date to allow for planning uncertainty, it would be premature and imprudent for the Company to commit to acquiring a supply resource (particularly one so far in the future) until the Company can determine the magnitude of the demand-side savings available in its service territory.

Q: Why should the Company continue in its efforts to secure the Polk Unit One site?

A: By moving to secure and prepare the site, the Company acquires the <u>option</u> to build on that site.

---

a more expensive mix of energy, T&D capacity, losses, and environmental effects. As affirmed in Florida Statute, the Company should also be acquiring all cost-effective renewables. (§ 366.81)

The decision to actually begin construction, regardless of the type of capacity added, can therefore be deferred until that time when power requirements will be known with greater certainty.

A more straightforward reason for securing the site is that TECo plans to use the land to install capacity in addition to the facility planned for 1995/96. In fact, Company plans call for eventual development of 1000 MW of capacity on the Polk County site.[57]

---

[57]Direct testimony of John B. Ramil, p. 10.

APPENDIX 1

MARKET BARRIERS AND THE
THE PAYBACK GAP BETWEEN
UTILITY AND CUSTOMER EFFICIENCY INVESTMENT DECISIONS

I. THE "PAYBACK GAP" AS EVIDENCE OF MARKET FAILURE

Q. How does a rapid payback requirement translate into a stricter investment criterion?

A. The required payback period for an investment translates directly into a required rate of return. A higher required return means one requires future benefits to be relatively large in order to sacrifice the use of funds today. Table I presents the required rates of return implied by different combinations of investment lives and payback requirements.

For example, a customer who requires a 20-year investment to pay for itself in two years reveals a 64% required rate of return (as shown in Table I, at the intersection of the 20-year investment column and the 2-year payback row). By discounting future benefits so highly such a customer would only spend a dollar today to save a $1.64 a year from now. By contrast, a utility that requires a 20-year supply project to yield a 6-

Table I. Required Rates of Return Implied By Payback Criteria Under Different Economic Lives

Payback Period (Years)	Economic Life of Investment (Years)				
	10	15	20	25	30
1	162%	162%	162%	162%	->162%<-
1.5	92%	92%	92%	92%	92%
2	63%	64%	64%	64%	64%
3	37%	39%	39%	39%	39%
5	17%	21%	22%	22%	22%
7	8%	13%	14%	15%	15%
10	0%	6%	8%	9%	10%
12		3%	6%	7%	-> 8%<-
15		0%	3%	5%	5%
20			0%	2%	3%

<u>Note</u>: Assumes monthly savings equate to a single cashflow at mid-year, with no inflation.

percent return on investment (compared to alternatives) will accept a 12-year payback period (as shown at the intersection of the 20-year investment column and the 12-year payback row).

Q. How does a required return lead customers to reject efficiency investments that would otherwise be attractive under a utility's lower discount rate?

A. The payback gap between utility and customer investment horizons is equivalent to a high markup to the life-cycle cost a utility would estimate for efficiency measures <u>if the utility paid for them directly and entirely</u>.

For example, consider the impact of a one-year maximum payback period which home builders

Table II. Derivation of Customer Markup to Societal Cost of Efficiency Improvement

ASSUMPTIONS	
Societal discount rate	8%
Levelized cost per kWh saved by efficiency, at societal discount rate	3 ¢/kWh
Economic life of efficiency measure	30 years
Customer's required return, implied by 1-year payback on 30-year measure (From Table I)	162%
RESULTS	
One-time investment equivalent to levelized payments for efficiency, at societal discount rate	33.8 ¢/kWh-Yr
Levelized cost of efficiency to customer, based on required customer return	54.6 ¢/kWh
Implicit customer markup to societal cost: 54.6/3 - 1 =	1722%

might require on efficiency investments. Suppose a new home builder and TECo are independently evaluating the merits of installing low-emissivity windows in new houses. ("Low-E" windows provide the heating and cooling savings of a third layer of glass for about a 10% price premium.) A 13% utility discount rate translates roughly into an 8% real rate (net of 5% inflation.)

The Company amortizes the price premium for the Low-E windows over their 30-year lives and comes up with a lifetime cost of 3 cents per saved kWh, which it considers a bargain compared to spending (say) 6 cents for new capacity over the same period. TECo would be indifferent to investing in the efficiency measure for a one-time capital cost of 33.8 cents/kWh-Yr (where the denominator equals the number of kilowatt-hours being saved each year), or paying 3 cents one kWh at a time over the 30-year life of the investment. (See Table II.)

Now consider the same choice from the home-builder's perspective. Referring to Table I, observe that her one-year payback period requires the same up-front investment of 33.8 cents/kWh-Yr savings to yield a return of 162%. At this rate, the low-E windows have a levelized cost of (same present worth as) 54.6 cents per kWh saved. Compared to the societal cost of 3 cents per kWh saved, the homebuilder treats the low-E windows as if she had to pay an extraordinarily high markup of 1722%.

Q. How would the 17-fold markup on efficiency measures in your example affect resource allocation?

A. If electricity costs 6 cents, the home builder would only be willing to invest in measures that would cost TECo 0.33 cents/kWh -- one-eighteenth of the price of electricity. She will reject all other measures (high-efficiency heat-pumps, extra wall insulation) that would cost more than a third of a cent per kWh from TECo's perspective. Her decision would force TECo to supply power for the less-efficient houses at our (assumed) marginal cost of 6 cents/kWh. Moreover, these opportunities will be lost for the lives of the houses once they go up, since it would not be economical to remove the conventional windows and replace them with the more efficient ones. Anything TECo can do to get the low-E windows and other measures into the house is cost-effective as long as the measures (and TECo's administrative costs) are less than 6 cents/kWh.[58]

Q. In general, what are the consequences when market barriers force customers to place a high markup on the costs of efficiency investments?

A. The result is that setting prices at marginal costs does not generate the market response predicted by economic theory; in reality, customers do not readily substitute efficiency for electricity. This is because the payback gap drives a wedge

[58]The incentives (rebates, grants, etc) are not costs per se, since they would cancel out payments by the home builder.

between what consumers will pay to save electricity and what utilities spend to produce it. The 17-fold markup in this example means that an electric rate of 6 cent/kWh would not motivate a customer to spend 6 cents per conserved kWh. Rather, the customer would only invest in efficiency that to a utility would cost about 1/3 cent/kWh. Equivalently, a utility would have to set prices seventeen times higher than marginal cost to stimulate the customer response that is optimal in this example, namely, installing the more efficient windows.

II. MARKET BARRIERS CONTRIBUTING TO THE PAYBACK GAP

Q. Are customers being irrational when they mark up the direct costs of efficiency measures?

A. Not at all. An aversion to capital-intensive electricity substitutes may be perfectly valid, especially since efficiency is paid for so much differently from electricity. The simplest reason that efficiency is so regularly passed over in favor of "business as usual" is that, as an investment, it is not available on the same pricing terms as electricity or fossil fuels already being purchased by customers. If it were -- either through market innovation, utility market intervention, or both -- even short-payback customers would be much more likely to choose efficiency whenever it was priced below electricity.

Q. What other factors contribute to customers' apparent aversion to efficiency investments?

A. At least four factors interact to compound the costs and dilute the benefits of efficiency measures to utility customers:

1. Limited access to relatively high-priced capital can constrain payback periods to durations far shorter than the useful lives of the investments;

2. Split incentives diminish the benefits that both owners and occupants of buildings receive from efficiency investments by conferring them on the other party;[59]

---

[59]Economists refer to this market imperfection as "unassigned property rights."

3. Real and apparent risks of various forms impede individual efficiency investments, particularly the illiquidity of conservation investments (financial risk), uncertainty over market valuation of efficiency (market risk), fear of "lemon technologies" (technological risk), and perceptions of service degradation; and

4. Inadequate, conflicting, and expensive information makes the search and evaluation costs of efficiency improvements high in terms of a customer's own time, effort, and inconvenience.

Q. How does limited access to capital constrain efficiency investment?

A. Efficiency investments lower operating outlays over time in exchange for higher initial outlays on the part of the investor. Individuals and businesses are often in no position to obtain capital to fund such commitments.[60] Homeowners and small business are often fully leveraged and unwilling to deplete savings to finance all economically justifiable efficiency investments. And while some consumers may be able to borrow the money to finance desired efficiency investments, borrowing terms are often far shorter than the life of the efficiency investment. The short amortization schedule pushes debt-service costs above the cashflow savings of the efficiency investment, shortening the maximum acceptable payback period.

Q. What do you mean by split incentives?

A. Many property owners do not pay the utility bills of the buildings they lease. Many building occupants do not own the buildings for which they pay utility bills. Making investments to lower the operating costs of tenants is rarely a high priority for landlords, just as spending money to raise property values (and therefore rents) is not terribly attractive to renters.

Equally serious institutional impediments retard efficiency investments at other stages of

---

[60]This is frequently because lenders fail to appreciate the value of efficiency. This could be characterized as an institutional impediment, a further consequence of inadequate information and risk perceptions.

the real estate market. Developers do not pay to operate the appliances, heating and cooling systems, or lighting in the homes and offices they build. Quite often they see their objective as minimizing the completion costs of the their buildings. This keeps margins high during tight markets, and protects against losses during slow periods.

Q. Explain how the elements of risk you listed restrain efficiency investments.

A. A higher level of perceived risk raises the rate of return required on the investment. Energy efficiency investments expose individual consumers to a variety of risks which a utility can reduce through diversification in its demand-side resource portfolio. Specific risks that tend to raise consumers' required return include the following:

> Financial risk: Efficiency investments are illiquid. Future savings from efficiency improvements are not marketable securities: there may be substantial penalties for earlier withdrawal. Often the efficiency investment becomes part of the building

it is installed in, making it extremely difficult to liquidate the investment without selling the building.

Technological risk: Few volunteer to be guinea pigs. For example, the perceived technological risks of advanced lighting equipment may be the single greatest obstacle to widespread market acceptance to date.

Market risk: Homeowners may reject efficiency investments whose annual savings look good on paper because they are unsure that the resale value of the home would increase enough to recover the costs. Similar concerns are justified for businesses contemplating an investment in highly efficient chillers or state-of-the-art lighting.

Q. Why does lack of information about efficiency constitute such a significant barrier?

A. Acquiring and critically evaluating information on the costs and performance of competing efficiency options is often prohibitively expensive for all but the largest and most sophisticated end-users.

Not only do consumers need to understand individual technologies; they need to know how measures interact. Savings from combining some measures are less than the sum of their individual savings (for example, high-efficiency glazing and insulation). Other measures are complementary (insulation and high-efficiency furnaces) or mutually reinforcing (lighting efficiency and cooling systems).

Exhibit ___PLC-2

Tampa Electric Company Planned Loads and Resources

Year [1]	Peak Demand Before C&LM [2]	Load Management [3]	Conservation [4]	Peak Demand After C&LM [5]	With Polk Unit One: Supply Resources [6]	With Polk Unit One: Resource Surplus [7]	With Polk Unit One: Reserve Margin [8]	Without Polk Unit One: Supply Resources [9]	Without Polk Unit One: Resource Surplus [10]	Without Polk Unit One: Reserve Margin [11]
1991	2,925	174	190	2,561	3,232	671	26.2%	3,232	671	26.2%
1992	3,088	180	208	2,700	3,307	607	22.5%	3,307	607	22.5%
1993	3,179	186	225	2,768	3,489	721	26.0%	3,489	721	26.0%
1994	3,278	193	242	2,843	3,489	646	22.7%	3,489	646	22.7%
1995	3,382	199	261	2,922	3,489	567	19.4%	3,489	567	19.4%
1996	3,481	205	277	2,999	3,639	640	21.3%	3,489	490	16.3%
1997	3,584	212	295	3,077	3,709	632	20.5%	3,489	412	13.4%
1998	3,689	218	316	3,155	3,709	554	17.6%	3,489	334	10.6%
1999	3,794	224	337	3,233	3,709	476	14.7%	3,489	256	7.9%
2000	3,902	230	361	3,311	3,709	398	12.0%	3,489	178	5.4%

Exhibit ___PLC–2
Tampa Electric Company Planned Loads and Resources

Notes:

[1]: Supply–side and C&LM resources are attributed to the earlier Winter peak; e.g. 1992 savings reduce 1991/92 peak demand.

[2]: (Net firm retail peak demand) + (net Sebring peak demand) + (conservation and load management)
Winter peak demand (both retail firm load and wholesale Sebring load) from Need Determination Study, Table 3–1. C&LM = [3]+[4].

[3]: Winter Load Management from Need Determination Study Table 3–2.

[4]: Winter Conservation from Need Determination Study Table 3–2.

[5]: [2]–[3]–[4]

[6]: [9] + Polk Unit One planned capacity.
Polk Unit One (150 MW) is installed mid–year 1995, and augmented (70 MW) a year later (Need Determination Study, page 90).

[7]: [6]–[5]

[8]: [6]/[5]–1

[9]: (Total Available Capacity) + (Sebring units) – (sale to TECO Power Services).
Total available capacity from Ten–Year Site Plan, page III–7, without the prospective additions after 1993.
Sebring units (49 MW) purchased 2/28/91 (Need Determination Study, page 42), and serve peak load beginning in 1992.
Capacity sale to TECO Power Services is 145 MW beginnng in 1993 (Need Determination Study, page 47).

[10]: [9]–[5]

[11]: [9]/[5]–1

Sources:

Ten–Year Site Plan:
Tampa Electric Company (April 1991). "Ten–Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines."

Need Determination Study:
Tampa Electric Company (September 1991). "Polk Unit One Need Determination Study." Docket No. 910883–EI before the Florida Public Service Commission.

Exhibit ___PLC-3

Tampa Electric Company's Projected Gross Electricity Requirements and Conservation and Load Mangement Resources

Page 1 of 3: Conservation Resources Compared with Electricity Requirements

Year	Growth in Pre-CL&M Electricity Requirements From 1991			Growth in Conservation From 1991			Growth in Conservation as % of Growth in Electricity Requirements		Conservation as % of Total Electricity Requirements	
	Peak (MW)	Sales (GWh)	Load Factor	Peak (MW)	Sales (GWh)	Load Factor	Peak	Sales	Peak	Sales
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1991	2,925	13,775	54%	190	141	8%			6.5%	1.0%
1992	163	258	18%	18	14	9%	11.0%	5.4%	6.7%	1.1%
1993	254	619	28%	35	29	9%	13.8%	4.7%	7.1%	1.2%
1994	353	991	32%	52	42	9%	14.7%	4.2%	7.4%	1.2%
1995	457	1,386	35%	71	56	9%	15.5%	4.0%	7.7%	1.3%
1996	556	1,776	36%	87	66	9%	15.6%	3.7%	8.0%	1.3%
1997	659	2,185	38%	105	77	8%	15.9%	3.5%	8.2%	1.4%
1998	764	2,596	39%	126	91	8%	16.5%	3.5%	8.6%	1.4%
1999	869	3,012	40%	147	102	8%	16.9%	3.4%	8.9%	1.4%
2000	977	3,430	40%	171	115	8%	17.5%	3.4%	9.3%	1.5%

Exhibit ___PLC-3
Tampa Electric Company's Projected Gross Electricity Requirements and Conservation and Load Mangement Resources

Page 2 of 3: Conservation and Load Management Resources Compared with Electricity Requirements

Year	Growth in Pre-CL&M Electricity Requirements From 1991			Growth in Conservation and Load Management From 1991			Growth in C&LM as % of Growth in Electricity Requirements		C&LM as % of Total Electricity Requirements	
	Peak (MW)	Sales (GWh)	Load Factor	Peak (MW)	Sales (GWh)	Load Factor	Peak	Sales	Peak	Sales
[1]	[2]	[3]	[4]	[12]	[13]	[14]	[15]	[16]	[17]	[18]
1991	2,925	13,775	54%	364	142	4%			12.4%	1.0%
1992	163	258	18%	24	14	7%	14.7%	5.4%	12.6%	1.1%
1993	254	619	28%	47	29	7%	18.5%	4.7%	12.9%	1.2%
1994	353	991	32%	71	42	7%	20.1%	4.2%	13.3%	1.2%
1995	457	1,386	35%	96	56	7%	21.0%	4.0%	13.6%	1.3%
1996	556	1,776	36%	118	66	6%	21.2%	3.7%	13.8%	1.3%
1997	659	2,185	38%	143	77	6%	21.7%	3.5%	14.1%	1.4%
1998	764	2,596	39%	170	91	6%	22.3%	3.5%	14.5%	1.4%
1999	869	3,012	40%	197	102	6%	22.7%	3.4%	14.8%	1.4%
2000	977	3,430	40%	227	115	6%	23.2%	3.4%	15.1%	1.5%

Exhibit ___PLC-3
Tampa Electric Company's Projected Gross Electricity Requirements and Conservation and Load Mangement Resources

Notes:
[1]: 1991 peak refers to the 1991/92 peak, and so on.
[2]: (Net retail and Sebring winter peak demand) + (Conservation and load management).
Net winter peak demand, both firm retail and wholesale Sebring load from Table 3-1.
Winter C&LM from Table 3-2.
[3]: Total sales to ultimate customers, plus energy conservation and load management.
Sales from Ten-Year Site Plan, page II-22. C&LM from Need Determination Study, Table 3-2.
[4]: [3]*1000/[2]/8760
[5]: Winter Conservation, from Table 3-2.
[6]: Energy Conservation and Load Management (from Table 3-2) minus
1 GWh of load management energy savings (from Table 3-3).
[7]: [6]*1000/[5]/8760
[8]: [5]/[2]
[9]: [6]/[3]
[10]: ([5] in 1991 + [5])/([2] in 1991 + [2])
[11]: ([6] in 1991 + [6])/([3] in 1991 + [3])
[12]: Winter Conservation + Winter Load Management, from Table 3-2.
[13]: Energy Conservation and Load Management, from Table 3-2.
[14]: [13]*1000/[12]/8760
[15]: [12]/[2]
[16]: [13]/[3]
[17]: ([12] in 1991 + [12])/([2] in 1991 + [2])
[18]: ([13] in 1991 + [13])/([3] in 1991 + [3])

Sources:
Unless otherwise stated, page and table numbers refer to the Need Determination Study.
Need Determination Study:
Tampa Electric Company (September 1991). "Polk Unit One Need Determination Study." Docket No. 910883-EI before the Florida Public Service Commission.
Ten-Year Site Plan:
Tampa Electric Company (April 1991). "Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines."

Exhibit ___ PLC-4
Utility Expenditures on DSM, as Percent of Revenues

	1991 expenditure (1991$) [1]	[1] as % of '91 revenues [2]	Total program expenditure (1991$) [3]	# yrs covered [4]	Avg annual expenditure [5]	[5] as % of '91 revenues [6]
BECo						
Res.	$11,052,489	0.9%	$31,714,800		$6,342,960	0.5%
C/I	$22,823,845	1.9%	$190,685,040		$38,137,008	3.0%
Total	$33,876,334	2.8%	$222,399,840	5	$44,479,968	3.5%
Com/Electric						
Res.	$1,608,000	0.4%	$14,552,000		$2,910,400	0.7%
C/I	$13,310,000	3.3%	$116,910,000		$23,382,000	5.5%
Total	$14,918,000	3.7%	$131,462,000	5	$26,292,400	6.2%
Eastern Utilities						
Res.	$2,673,900	1.1%	$18,451,700		$3,690,340	1.4%
C/I	$7,198,180	2.9%	$58,194,080		$11,638,816	4.4%
Total	$9,872,080	4.0%	$76,645,780	5	$15,329,156	5.8%
NEES						
Res.						
C/I						
Total	$85,000,000	5.3%	$1,608,105,200	20	$80,405,260	4.7%
New York State Electric and Gas						
Res.						
C/I						
Total	$25,409,000	2.2%	$1,550,063,000	19	$81,582,263	6.7%

Notes:

Boston Edison 1991 figures (in '91$) from Table 1 of Exh. BE-RSH-3 to DPU 90-335; figures are only for spending on conservation (load management excluded); these figures are an update to BECO 1990 plan. Boston Edison figures other than 1991 are from "The Power of Service Excellence," (March '90), Appendix 1-A. BECo's figures, reported as 1990 dollars, have been adjusted to 1991 dollars (infl. = 4%).

Com/Electric expenditure data from Mass. DPU 91-80, 4/15/91 (1991 dollars).

Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991," (2/91) 1991 dollars assumed.

NEES 1991 figures from "Demand Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribats et al., NARUC Santa Fe 1991 Conference Proceedings (1991 dollars). Remaining NEES figures from their "Conservation and Load Management Annual Report" (5/90) (1990 dollars, adjusted to 1991 (4% inflation assumed). NEES 1988 revenues from NEES' 1989 Annual Report, p. 18.

NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90) Vol. 1 (originally reported in nominal dollars; adjusted to '91$, 4% infl. assumed; prog. costs for 1991-2008). NYSEG ultimate consumer revenues from 1989 annual report, adjusted annually by 2% for growth and 4% for inflat

All utilities' (except for NYSEG and NEES) revenues from the Energy Information Administration's "Financial Statistics of Selected Electric Utilities, 1988" (published 1990). 1988 revenues have been adjusted annually by 2% for growth and 4% for inflation.

Exhibit ___ PLC-5
1991 DSM Savings as Percent of 1991 Peak and Sales

	DSM MW	Peak MW	MW svgs as % of peak	DSM GWh	Sales GWh	GWh svgs as % of sales
	[1]	[2]	[3]	[4]	[5]	[6]
BECo						
Res.	3	689	0.4%	18	3,523	0.5%
C/I	17	1,948	0.9%	74	9,404	0.8%
Total	20	2,637	0.8%	92	12,927	0.7%
Com/Electric						
Res.	NA			7	1,703	0.4%
C/I	NA			72	1,827	3.9%
Total	NA			79	3,531	2.2%
Eastern Utilities						
Res.	1	NA		5	1,601	0.3%
C/I	11	NA		23	2,613	0.9%
Total	12	860	1.4%	27	4,213	0.6%
NEES						
Res.	NA			NA		
C/I	NA			NA		
Total	46	4,441	1.0%	141	24,553	0.6%
Northeast Utilities						
Res.	25	NA		52	9,912	0.5%
C/I	129	NA		173	14,608	1.2%
Total	155	5,154	3.0%	225	24,520	0.9%
NYSEG						
Res.	15	NA		30		
C/I	20	NA		52		
Total	35	2,710	1.3%	82	13,578	0.6%
United Illuminating						
Res.	4	NA		11	1,808	0.6%
C/I	35	NA		36	3,380	1.1%
Total	39	5,530	0.7%	48	5,189	0.9%

Notes:

Boston Edison 1991 figures from Table 1 of Exh. BE-RSH-3 to DPU 90-335; figures are only for conservation program savings (load management excluded); sales and peak projections from "Long Range Integrated Resource Plan," Vol 2 (1/90).

Com/Electric savings data from Mass. DPU 91-80, 4/15/91
Com/Electric sales data from "Long Range Forecast of Electric Power Needs and Requirements," (12/1/89) Vol. 1.

Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991," (2/91).
Eastern Utilities load and sales projections from DRAFT Load Forecast, Vol 2. Figures are for 1990, as no 1991 figures were available.
Effect of DSM has been added back to EUA's post-dsm forecast figures.

NEES 1991 figures from "Demand Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribats et al., NARUC Santa Fe 1991 Conference Proceedings (1991 dollars).

Northeast Utilities data from "1991 Forecast of Loads and Resources" (3/1991).

NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90), Vol 1, Table 3.

All UI data from United Illuminating's "Report to the Connecticut Siting Council," (3/1/91).

Exhibit ___ PLC-6 (part 1)
Cumulative and Total Demand Savings, as Percent of Growth and Peak

	Peak savings (MW)	Peak load (MW)	Peak savings as % of peak	Cum. growth in peak savings (MW)	Cum. peak growth (MW)	Growth in peak savings as % of peak grth
	[1]	[2]	[3]	[4]	[5]	[6]
BECo (growth 1990-94 inclusive)						
Res.:	8	734	1.1%	7	64	10.6%
C/I:	109	2,159	5.0%	109	295	36.9%
Total:	117	2,893	4.0%	116	359	32.3%
Eastern Utilities (growth 1991-95 inclusive)						
Res.:	7	NA		7	NA	
C/I:	73	NA		73	NA	
Total:	80	949	8.4%	80	99	80.8%
NEES (growth 1991-1995 inclusive)						
Res.:	NA					
C/I:	NA					
Total:	340	4,581	7.4%	221	403	54.8%
New York State Electric and Gas (growth in 1991-2008 inclusive)						
Res.:	NA					
C/I:	NA					
Total:	846	4,470	18.9%	788	1,810	43.5%
Northeast Utilities (growth 1992-2000 inclusive)						
Res.:	77	NA		52	NA	
C/I:	743	NA		613	NA	
Total:	819	6,208	13.2%	665	1,054	63.1%
United Illuminating (growth 1992-2010 inclusive)						
Res.:	48	NA		44	NA	
C/I:	262	NA		227	NA	
Total:	310	1,554	19.9%	270	445	60.7%

Exhibit ___ PLC-6 (part 2)
Cumulative and Total Energy Savings, as Percent of Growth and Sales

	Total energy savings (GWh)	Total projected sales (GWh)	Energy savings as % of sales	Cum. growth of energy svgs (GWh)	Cum. sales growth (GWh)	Energy savings as % of growth	DSM load factor
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
BECo (growth 1990-94 inclusive)							
Res.:	73	3,709	2.0%	66	295	22.3%	102%
C/I:	454	10,145	4.5%	454	1,205	37.6%	48%
Total:	527	13,854	3.8%	520	1,500	34.6%	51%
COM/Electric (growth 1991-95 inclusive)							
Res.:	62	2,014	3.1%	62	348	17.9%	NA
C/I:	688	2,571	26.8%	688	854	80.6%	NA
Total:	750	4,585	16.4%	750	1,202	62.4%	NA
Eastern Utilities (growth 1991-95 inclusive)							
Res.:	37	1,697	2.2%	37	100	37.1%	59%
C/I:	198	2,924	6.8%	198	276	71.8%	31%
Total:	236	4,622	5.1%	236	377	62.5%	34%
NEES (growth 1991-1995 inclusive)							
Res.:	222	8,208	2.7%	156	217	71.9%	NA
C/I:	757	14,487	5.2%	496	1,607	30.9%	NA
Total:	1,120	25,070	4.5%	750	1,936	38.7%	38%
New York State Electric and Gas (growth in 1991-2008 inclusive)							
Res.:	912	NA					NA
C/I:	1,867	NA					NA
Total:	2,794	22,170	12.6%	2,779	8,855	31.4%	38%
Northeast Utilities (growth 1992-2000 inclusive)							
Res.:	556	10,890	5.1%	504	978	51.5%	83%
C/I:	2,895	18,983	15.2%	2,722	4,376	62.2%	45%
Total:	3,460	30,180	11.5%	3,232	5,366	60.2%	48%
United Illuminating (growth 1992-2010 inclusive)							
Res.:	47	2,259	2.1%	36	451	8.0%	11%
C/I:	776	5,021	15.4%	739	1,640	45.1%	34%
Total:	827	7,347	11.3%	777	2,097	37.0%	30%

Weighted average of load factors for BECo, Eastern Utilities, Northeast Utilities, and United Illuminating:	Res.:	58%
	C/I:	42%
	Total:	43%

Weighted average of total load factors, for BECo, EUA, NEES, NYSEG, UI, NU.	41%

Notes to Exhibit ___ PLC-6, parts 1 and 2:

[1]: Energy (and peak) savings are for the final year of the interval indicated.
[2]: Total sales (and peak) figures are for the final year of the interval indicated, and are pre-DSM forecasts; that is, they do not take into account reductions due to DSM.
[3]: [1]/[2]
[4]: [1] minus the savings (or peak) of the year preceding the first year of the specified interval.
[5]: [2] minus the sales (or peak) of the year preceding the first year of the specified interval. For example, BECo's projected sales growth equals 1994 sales minus 1989 sales.
[6]: [4]/[5]
[7]: (part 2 only) load factor is calculated as ([2] of part 2)/([2] of part 1)*1000/8760.

Sources:

Boston Edison savings figures are from "The Power of Service Excellence," (March '90), Appendix I-C.
Load figures from Long-Range Integrated Resource Plan 1990-2014, Vol. II. (5/1/90).

Com/Electric savings data from Mass. DPU 91-80, 4/15/91
Com/Electric sales and peak data from "Long Range Forecast of Electric Power Needs and Requirements," (12/1/89) Vol.
Note that Com/Electric's savings as reported in column [1] of part 2 do not include the effects of DSM implemented prior t

Eastern Utilities load and sales projections from DRAFT Load Forecast, Vol 2.
Eastern Utilities data from "Energy Solutions: An Overview of Montaup's Residential C&LM Programs, 1991" and "Energy Solutions, An Overview of Montaup's C/I C&LM Programs, 1991" (2/91).
Note that EUA's savings as reported in column [1] of each table do not include the effects of DSM implemented prior to 19

NEES figures from "Integrated Resource Management Draft Initial Filing, Technical Volumes," May 20, 1991.

NYSEG figures from their "Demand Side Management Summary & Long Range Plan," (10/90), Vol. 1, Table 3.

Northeast Utilities data from Northeast Utilities, "1991 Forecast of Loads and Resources for 1991-2010," (March 1991).

United Illuminating data from UI's "Report to the Connecticut Siting Council," (3/1/91).

Exhibit ___ PLC-7
Cost of Residential and C/I DSM Savings

	Budget (1991$)	Incremental MW savings	Incremental GWh savings	DSM capacity factor	Amortized budget	Gross $/kWh
	[1]	[2]	[3]	[4]	[5]	[6]
BECO (DSM in 1990-1994)						
Res	$31,714,800	7	66	108%	$3,062,398	$0.0464
C/I	$190,685,040	109	454	48%	$18,412,647	$0.0406
Total	$222,399,840	116	520	51%	$21,475,044	$0.0413
Com/Electric (DSM in 1991-1995)						
Res	$14,552,000	NA	62	NA	$1,405,149	$0.0227
C/I	$116,910,000	NA	688	NA	$11,288,890	$0.0164
Total	$131,462,000	NA	750	NA	$12,694,039	$0.0169
EUA (DSM in 1991-1995)						
Res	$18,451,000	7	37	61%	$1,781,638	$0.0479
C/I	$58,194,080	73	198	31%	$5,619,251	$0.0283
Total	$76,645,080	80	236	34%	$7,400,889	$0.0314
NEES (DSM in 1990-2009)						
Total	$1,608,105,200	1162	2,285	22%	$155,279,474	$0.0680
1991 only:	$85,000,000	46	141	35%	$8,207,644	$0.0582
New York State Electric and Gas (DSM in 1991-2008)						
Total	$1,550,063,000	788	2,779	40%	$149,674,889	$0.0539

Assumptions:

Life of DSM savings	15
Real discount rate	5%

Notes:

[1],[2],[3]: see Exhibit PLC-6 for source, except for NEES, whose 1990-2009 figures are from the 1990 Conservation and Loa Management Annual Report, and whose 1991 figures are from"Demand-Side Management at New England Electri Implementation, Evaluation and Incentives," Alan Destribates et al., NARUC Santa Fe 1991 Conference Proceedin All utilities' expenditures and savings are cumulative over the life of the program.

[3]: Note that line losses are not included; this results in overstating of the final cost of DSM.

[4]: [3]*1000/[2]*8760

[5]: [1], amortized over 15 years, at a 5% real discount rate; real discount rate derived from TECo's Conservation Plan, Docket No. 890737-PU, filed 2/90 (9.76% nominal discount rate, 4.5% inflation).

[6]: [5]/[3]*10^6

'Exhibit ___ PLC-8 (part 1): Incentives Paid in Collaboratively-Designed Commercial/Industrial Energy Conservation Programs

	Programs targeting conservation market sectors							*Programs targeting end-uses*	
	New constrctn	Remodel/ replace	Retrofit Large C/I	Retrofit Small C/I	Existing industrial	Agric.	Industrial new constr	Motors	Lighting
BECo [1]	100% IC +d [2]	100% IC	100% TC or 1 yr pb [3]	100% TC					
COM/Elec [4]	100% IC +d [5]	100% IC +d (NC)	100% IC [6]	100% TC	90-100% IC [7]		1.5 yr pb	TBD	
CVPS	100% IC +d [8]	100% IC [9]	1.5 yr pb	1.5 yr pb	1.5 yr pb	1.5 yr pb	1.5 yr pb	100% avg IC	75% TC +f [10]
EUA	100% IC +d [11]	100% IC +d (NC)	100% TC [12]	100% TC [12]					
GMP	100% IC apx, +d [13]	100% IC	2 yr pb	1 yr pb		1 yr pb			
NEES	100% IC +d [14]	100% IC +d, (NC) [15]	100% TC/IC [16]	100% TC/IC					
NYSEG [17]	100% IC +d [18]	100% IC apx	1.5 yr pb +f	100% TC	100% avg IC [19]	100% avg IC [19]			100% avg IC [19]
UI	57-93% IC +d [20]	57-93% IC +d (NC)	25% TC, apx +f [21]	25% TC, apx +f [21]					
WMECo	100% IC +d [22]	TBD [23]	66% TC or 1 yr bp [24]	100% TC [25]					100% IC [26]

Key:

apx :	Approximately	IC:	Incremental Costs
avg :	Average	(NC):	Covered under new construction program
blank cell:	Utility does not have such a program	n yr pb:	n Year Payback Buydown (n=# of yrs)
+d :	+ Design assistance	TBD:	To be determined
+f :	+ Financing	TC:	Total Costs

Notes to Exhibit ___ PLC-8, part 1:

[1]: BECo also offers a performance contracting program (incentive: 100% TC) and Design Plus, a prog. targeting large C/I customers willing to invest in upgrading their electrical systems (incentive: 50% measure cost, 100% design cost).

[2]: Design: based on annual kWh savings, $.005/annual kWh saved for bldgs < 80,000 sq ft; $.01/annual kWh saved for larger bldgs; 25% bonus for exceeding Article 20 code levels by more than 30%.

[3]: Full installation cost for institutions; non-institutional incentive is total cost of retrofit less projected value of first year energy and demand savings.

[4]: Commonwealth Electric also has a dedicated non-profit program and schools program which pay 100% of incremental costs.

[5]: Design incentive per annual kWh saved: $.01 for bldgs < 80,000 square feet, $.005 for larger bldgs, bonus incentive for comprehensive designs, total capped at $.025 (small bldg) and $.0125 (large bldg); caps periodically revised.
Industrial new construction: 1.5 yr payback buydown.

[6]: Incentives offered either as cash payment, bill credit, or payment to 3rd party such as contractor or bank; lower level of funding (90%) for single end-use projects.

[7]: Same as [4], except no penalty for a less comprehensive program.

[8]: Full incremental costs to Act 250 customers only; others will be offered incentives to offset incremental costs; capped design incentive based on estimated energy savings, bonus to encourage comprehensive, highly efficient designs.
Industrial new construction: 1.5 year payback buydown.

[9]: 1.5 year buyback for national accounts

[10]: Phase 1(test facilities for promotion of prog.): cust must pay 25% of cost of products and labor; CVPS will provide 0% financing. Phase II incentives are not specified.

[11]: Design: 6% of construction incentive, capped at $10,000; constuction: 100% of IC up to $50,000, after which customer must contribute 1 year's bill savings.

[12]: Retrofit: 100% full installed cost; replacement/upgrade: 100% incremental cost, capped at $100,000 per customer.

[13]: Design: incremental cost (to 5% of construction incentive); construction: approximately full incremental cost.

[14]: Design incentive of up to 6% of total equipment incentive.

[15]: Customers who are renovating are covered under new construction; official definition of "renovating" is still TBD; personal communication, Don Robinson (NEES) to Sabrina Birner, 4/18/91.

[16]: Except for lighting, where only the most efficient options have full incentives.

[17]: NYSEG also offers an HVAC program paying 100% of average incremental costs.

[18]: Capped design cost.

[19]: NYSEG bases incentive on average incremental costs, i.e., if a customer's incremental costs are unreasonably higher than average incremental costs, NYSEG reserves the right to pay only average incremental incremental costs.

[20]: 57% base incentive for meeting a component standard; higher incentive for exceeding standard; bonus for meeting standards on all components; design grant available, amount depends of size, complexity of project, and on engineer's experience.

[21]: Incentive schedule as follows: if measure pays for itself in 0-2 years, 0% incentive; 2-3 years, 20%; 3-4 years, 30%; 4+ years, 40%; on the average, UI expect this incentive to be approx. 25% of total installation cost.

[22]: Prescriptive area:up to full incr cost, based on kW and/or kWh reductions from baseline (subject to change in 1991); comprehensive area: up to full incr cost, capped at $.035/lifetime kWh for measures, $.005 for design; bonus incentives available; program cap being revised.

[23]: Incentive structure for WMECo's remodel/replace program still being determined (person communication, Nancy Benner to Sabrina Birner, 4/17/91)

[24]: Lighting: fixed $ amount per item (installation, design etc excluded); manufacturing: 1 year payback buydown of installed cost; non-manufacturing: least of 2 year payback buydown of installed cost or 66% of total cost; also valid for customer-initiated DSM.

[25]: For customers with an avg peak demand < 50 kW; customers with avg peak demand between 50 and 250 kW receive a free audit and installation of about $100 worth of low-cost measures, and have the option of participating in WMECO's lighting program.

[26]: Personal communication, Martha Samson (Northeast Utilities) and Sabrina Birner, 4/18/91.

Exhibit ___ PLC-8 (part 2): Incentives Paid in Collaboratively-Designed Residential Energy Conservation Programs

	Programs targeting conservation market sectors						*Programs targeting end-uses*				
	Gen'l use cust.	Multi-family	New constr.	Low income	Energy fitness	Public Hous'g	Lighting (CF bulbs)	Elec. heat cust.	Appliance	Efficient A/C	High-eff water heater
BECo	up to 100% TC	up to 100% TC	based on IC [1]		100% TC	up to 100% TC [2]	100% TC +cat, +pop [3]	up to 100% TC	labeling only [4]	tune-up, rebate TBD [5]	
Com/Elec	100% TC [6]	100% IC [7]	reduce or eliminate IC [8]	100% TC	100% TC	100% TC	100% TC +cat, +pop [9]	100% TC	labeling only		
CVPS	50% of cost [10]						apx 50% TC +cat, +pop [11]		coupons [12]		
EUA	100% TC [13]	100% TC [13]	apx avg IC [14]	100% TC [13]			100% TC +cat [15]	100% TC [13]	labeling only	$125/ton	
GMP	TBD [16]		TBD [16]				+pop, +cat [17]		coupons [18]		
NEES		100% TC/IC	100% TC/IC		100% TC/IC		100% TC/IC	100% TC/IC	[19]		100% TC/IC
NYSEG [20]	100% TC	100% IC +f [21]	apx 100% IC	100% TC			100% TC +cat, +pop [22]	100% TC	TBD		100% IC apx
UI [23]	100% TC		based on kWh savgs [24]				100% TC +pop [25]	100% TC [26]	rebates, labeling [27]	cust and dealer incentives	100% TC [28]
WMECo [29]	100% TC	100% TC	apx avg IC [30]	100% TC		100% TC [31]	100% TC +cat, +pop [32]	100% TC	2nd frig. disposal		100% TC

Key:

apx :	Approximately	+f :	+ Financing
avg :	Average	IC:	Incremental Costs
blank cell:	Utility does not have such a program	+ pop:	+ point-of-purchase discounts
+cat:	+ catalogue	TBD:	To be determined
+d :	+ Design assistance	TC:	Total Costs

sab incentiv.wk1

Notes to Exhibit ___ PLC-8, part 2:

[1]: Incentives are based on avoided costs and on average incremental measure costs, and will be designed to maximize participation rates and to eliminate market barriers.

[2]: BECo will consider incentives for measures that only become cost-effective when both the energy and non-energy benefits are considered; incentive would reflect payment needed to acheive desired market penetration; incentive would not exceed the lesser of measure costs or the value of the savings to BECo over the measure life.

[3]: BECo catalogue and point-of-purchase rebates are set to 2/3 of the retail cost for compact fluorescent bulbs, 1/4 of cost for halogen bulbs.

[4]: Incentives do not appear cost-effective at this time, but will periodically evaluate and implement rebates for high-efficiency eq't.

[5]: BECO will pay for a portion of the cost of an A/C or Heat Pump tune-up, will also offer rebates (level TDB) for efficient A/C, heat pumps.

[6]: 100% of total cost paid for hot water measures; four free compact fluorescent bulbs/household; add'l bulbs available at reduced price through catalogue; COM/Electric will pay some portion of hardwire fixture retrofits; free appliance maintenance and customer education.

[7]: For electric heat customers, in many cases, measures which are deemed important for the building owner to invest in will be cost-shared: COM/Electric will pay up to avoided costs, and the owner will provide the rest of the financing, part of which may be debt.

[8]: Level of incentive will be based on results of other Massachusetts utilities' residential new construction programs; 100% IC expected for multi-family housing.

[9]: Also, mail-order rebates for bulbs ($5 or $7.50 per bulb) and fixtures (up to $30); point of sale rebates.

[10]: Energy conservation measures available by mail order or at district office (no direct installation); there will be a maximum incentive per customer.

[11]: Point-of-sale discounts of 50% (approx $7.10) for bulbs, $20 for fixtures, + dealer incentive; mail order incentive of approx. 50% of bulb cost; other incentives to be investigated.

[12]: Refrigerator, $50; freezer, $50, room A/C, $20; also, $50 paid for disposal of second refrigerators.

[13]: Under its umbrella "Residential Retrofit Program," EUA has designed stategies to penetrate the following sectors: single family electric space and water heating; multi-family electric space and water heating; general use customers; and low income customers.

[14]: Fixed incentives offered through Energy-Crafted Homes program: single-family electric: $1650; multi-family electric: $900; lighting: $25/hard-wired compact fluorescent fixture; these incentives are meant to cover the average incremental cost to the builder for going for a Code-built house to an Energy Crafted Home.

[15]: Free compact fluorescent bulbs offered under programs listed in [13]; additional bulbs available through a catalog at 65% – 70% of retail cost.

[16]: Under review (incentives and fuel switching still unresolved).

[17]: Bulbs, 50%, fixtures $20 (point of sale or mail order)

[18]: Coupons of $50 for refrigerators and freezers; also $50 paid for second fridge disposal;dealer incentives.

[19]: Rebate anticipated to be less than incremental costs.

[20]: NYSEG also offers a "Renovation, Remodel and Equipment Upgrade" program to capture energy savings from the renovation and remodeling of residential properties; incentives approximate incremental costs.

[21]: 100% total cost for electrically heated properties; non electrically heated properties receive up to full incremental costs: financing available for non-electric heat customers.

[22]: In addition, charitable groups work w/ NYSEG to sell the bulbs door-to-door at low cost.

[23]: UI also offers an AC/heat pump tune-up program, and an energy conservation loan program for households undertaking large-scale energy efficiency improvements.

[24]: Total UI investment to be less than present value of avoided costs, currently estimated at approx. $1,100/unit.

[25]: UI also offers dealer incentives.

[26]: Full cost of measures installed directly; incentive payments and financial package for other measures implemented.

[27]: Rebates for efficient AC, based on avoided cost; appliance labeling for refrigerators, freezers, room AC.

[28]: Tank and pipe wrap, early retirement of rental water heaters, replacement with high-efficiency units.

[29]: WMECO also offers a "Neighborhood Program" which will target urban customers on a neighborhood-by-neighborhood basis.

[30]: 1-2 family: electric heat: $1,650/home; fossil fuel heat: $150/home; lighting: $200/unit.
Multifamily: electric heat: $900/unit; fossil fuel heat: $75/unit; lighting: $200/unit.

[31]: In some cases, the PHA may share in the cost of installation. This cost may be important with buildings requiring nonenergy-related modernization measures which can occur at the same time as measures installations.

[32]: Bulbs distributed free through other programs; mail order catalog offering bulbs at discount (discount not specified in Plan); point of purchase rebates offered (rebate not specified in Plan).

Sources and General Comments for Exhibit ___ PLC-8:

Comments

Utilities will not pay more than avoided costs for a measure.

Some customers may, for aesthetic reasons, pick a more expensive measure over the recommended measure. In this case, the customer must pay the incremental cost of the expensive measure over the recommended measure.

As of 4/15/91, CVPS' and GMP's programs have not yet been approved by the Vermont DPS.

Sources:

Boston Edison, "Energy Efficiency Partnership, Commercial Industrial Conservation Programs," and "Energy Efficiency Partnership, Residential Conservation Plans," (11/90).

Central Vermont Public Service Docket 5270-CV-3, Sept 7 1990, "Concensus Filing of CVPS Collaborative Requesting Approval of Conservation, Efficiency and Load Management Programs."

COM/Electric, "Mass. State Collaborative Phase II Detail Plans" (10/89).

Eastern Utilities, "Energy Solutions: An Overview of Montaup's Commercial/Industrial C&LM Programs - 1991" (2/91).

Green Mountain Power Collaborative Program Filing, December 17th, 1990.

New England Electric System, Mass. DPU Docket No. 90-261, discovery response DR-DPU-PD 2-6, and Appendix H to testimony of Witness Flynn, "Design 2000."

NYSEG, "Demand Side Management Summary and Long Range Plan," (Oct 1990).

United Illuminating, "Energy Action '90," (4/90).

Western Massachusetts Electric Company DPU Application for Pre-Approval of Conservation and Load Management Program, Testimony of Earle Taylor, Jr. (3/91).

EXHIBIT____PLC-9: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

A: Boston Edison

Residential

Program	Target population	Measures	Delivery	Special features
Energy Eff. Lighting	All customers	cold-ballasted & other fluorescents, high pressure sodium	Direct installation	
Energy Fitness	general use, urban customers	lighting, appliance, elec. H2O heaters	Direct installation	
Appliance Labeling	Buyers of refrig., freezer, room A/C	Labeling	Point-of-purchase	
Heat Pump/AC Tune Up	customers with heat pump, central A/C; high use	Tune ups	Direct installation	
Multifamily Elec. Eff.	multi-family	space heat, lighting, elec. H2O heat, education	Direct installation	
Public Housing	public housing authorities	insul., vent., air seal, A/C filter replace, lighting	Direct installation	Considers incntvs. for custom measures
New Construction	new homes, high-rise, major remodeling	insul., vent., lighting, eff. heat, eff. appliances	Direct installation	
Elec. Heat/High Use	high use customers in 1-4 unit bldgs., low-inc.,	space heat/cool, lighting, elec H2O heat, education	Direct installation	Considers incntvs. for custom measures
WattBusters	customers with elec. H2O heat in 1-4 unit bldgs.	elec. H2O heat	Direct installation	
HVAC	A/C, heat pump new install. & replacement	central A/C, heat pump	Direct installation	

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Encore	Institutional customers	varies with ESCO	ESCO's	Performance contracting
C/I New	New construction, major renovation	Lights, H2O heat, HVAC, refrig., cooking	Direct installation	Incentives for some other customer-proposed measures
C/I Small	Customers with 150- kW peak demand	Lights, HVAC, refrig., elec. H2O heat, cooking	Direct installation	Incentives for some other customer-proposed measures
C/I Large	Customers with 150+ kW peak demand	Lights, HVAC, refrig., ind. process		
C/I Remodel & Replace	Replacements, remodeling	Lights, HVAC, refrig., elec. H2O heat, cooking, motors	Direct installation	
Design Plus	Largest 1500 customers	Lights, HVAC, controls, elec. H2O heat, motors		

Notes:

Shaded programs are lost opportunity programs.

Boston Edison also offers a commercial/industrial load management program.

Source:

Boston Edison Energy Fitness Plan: Residential Conservation Programs.

Boston Edison Energy Efficiency Partnership: Commercial and Industrial Conservation Programs.

EXHIBIT____PLC-9: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

B: Eastern Utilities

Residential

Program	Target population	Measures	Delivery	Special features
Residential Retrofit	single/multi fam. elec. space & H2O heat, gen. use & low inc.	comp. fluor., refrig. coil clean, H2O heat wraps, pipe insl., repl. A/C filters	Direct installation	xtra insl. for space heat customers
Energy Crafted Home	new construction	insul., vent., high eff. lighting		incentives to builders
Appliance Labeling	all buyers of hi-eff. refrig., freezer, A/C, H2O heaters	Labels		
Efficient Central A/C	new or replacement A/C	A/C with 11.0+ SEER	Direct installation	Incentives to contractors

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
C/I Retrofit	All customers	lighting, elec. H2O heat, HVAC, motors	Direct installation	
Energy Eff. Construction	New construction	Lights, motors, HVAC, refrig., envelope		Incentives for some other customer-proposed measures

Notes:

Shaded programs are lost opportunity programs.

Eastern Utilities also offers a commercial/industrial load management program.

Source:

Energy Solutions: An Overview of Montaup's Residential C&LM Programs – 1991.

Energy Solutions: An Overview of Montaup's Commercial and Industrial C&LM Programs – 1991.

EXHIBIT____PLC-9: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

C: New England Electric

Residential

Program	Target population	Measures	Delivery	Special features
Appliance Efficiency	Buyers of refrig., A/C, freezer, elec. H2O heater	Labeling	NA	
Energy Fitness	Low-income, moderate use	Fluorescents, clean refrig. coils, change A/C filters	Direct installation	Water cons. measures included
Water Heater Rebate	all customers	Hi-eff. elec. H2O heater	NA	Rebates to wholesalers, dealers, plumbers
Water Heater Rental	all customers	Hi-eff. elec. H2O heater	Direct installation	
Water Heater Wrap	elec. H2O heating customers	water heater wrap	Direct installation	

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Lighting Rebate	All customers	4&8 ft. fluor., U-shaped, compact fluor., ballasts & fixtures	Dealer rebate applications	Incentives to lighting dealers
Design 2000	New construction	Lights, heat vent., A/C, motors, HVAC, envelope	Archtcts. or menu-based	Incentives to dvlprs., owners, archtcts., engrs.
Energy Initiative	C/I; govt.	lighting, motors, adj. spd. drives, HVAC, shell, ind. processes	Direct installation	
Performance Contracting	Customers with 500+ kW demand	varies with ESCO	ESCO's	
Small C/I	Customers with 100- kW demand or 300,000- kWh usage	fluorescent, halogen, other lights	Direct installation	

Notes:
Shaded programs are lost opportunity programs.
NEES also offers commercial/industrial load management programs.

Source:
NEES Conservation and Load Management Annual Report. May 1, 1990.

EXHIBIT____PLC-9: SPECIFICS OF COLLABORATIVELY DESIGNED DSM PROGRAMS

D: Western Massachusetts Electric

Residential

Program	Target population	Measures	Delivery	Special features
Electric Heat	Customers in 1–4 unit bldgs. w/ 15,000+ kWh/year	H2O heat wrap, insul., comp. fluorescents, ventilation, windows	Direct installation	
Domestic Hot Water	All customers	H2O heat wrap, insul., comp. fluorescents, fixture replacements	Direct installation	
Multifamily	Private multifamily bldgs. w/ 5+ units	H2O heat wrap, insul., comp. & other fluors., vent., windows, fixt. replace.	Direct installation	
Public Housing	Units w/ elec. heat, dom. hot H2O; general service bldgs.	H2O heat wrap, insul., comp. & other fluors., hi–pressure Na, vent., windows	Direct installation	
Energy Eff. Lighting	All customers	comp. fluors., exit signs, fixt. replace., halogens, hi–pressure sodium	Direct; catalog; point–of–purchase rebate	
Appliance Pick–up	Buyers of new equipment	refrigerators, freezers	Direct installation	
Energy Crafted Home	New homes under three stories	lighting, space & H2O heat, insul., vent., windows	Direct installation	Incentives to builders

Commercial/Industrial

Program	Target population	Measures	Delivery	Special features
Energycheck	Customers with 250– kW	lights, ballasts, heat & cool, motors, adj. spd. drives	Direct installation	
Lighting Rebate	Small & medium customers	comp. & T–8 fluors., hybrid & elec. ballasts, reflectors, exit signs, sensors	Direct installation	
Energy Conscious Constr.	New construction and major renovation	Lights, HVAC, refrig., elec. H2O heat, cooking	Direct installation	$1,000 brainstorming incntv.; bonus for 20+% reduction
Energy Action Program	Customers with 250+ kW peak demand & 50,000+ sq. ft.	Lights, HVAC, chillers, condnsrs., evaporators, compressors	Direct installation	
Customer Initiated	Customers with 250+ kW peak demand	HVAC, motors, lighting, industrial process	Direct installation	
Streetlighting	Municipal governments	4,000 lumen Hg vapors to 6,300 lumen hi–pressure sodium	Direct installation	

Notes:

Shaded programs are lost opportunity programs.

WMECo also offers a residential load management program.

Source:

Application of Western Massachusetts Electric Company for Pre–Approval of *Conservation and Load Management Programs.*

Exhibit ___PLC-10
Participation Rates in TECo's DSM Programs

Year	Res. Alternate audit	Res. RCS audit (paid)	C/I Free audit	C/I Compre-hensive audit	Res. Ceiling insulation	Res. Prime-time load mg't	C/I Load mg't, ext'd	C/I Load mg't, cyclic	Res. Heating and cooling	C/I Indoor lighting	C/I Standby gen.	C/I Conser-vation value
1982	4.5%	0.9%	0.8%	0.1%	0.0%	1.8%	0.0%	0.0%	4.9%			
1983	10.1%	1.1%	1.8%	0.2%	2.7%	2.5%	0.00%	0.0%	8.5%			
1984	15.5%	1.1%	2.9%	0.4%	7.2%	4.5%	0.00%	0.2%	13.5%			
1985	20.4%	1.1%	4.0%	0.4%	1.1%	7.2%	0.01%	0.4%	17.8%			
1986	25.3%	1.1%	4.7%	0.4%	1.6%	10.8%	0.01%	0.3%	19.6%			
1987	26.4%	1.0%	6.0%	0.4%	2.0%	13.1%	0.01%	0.2%	21.4%			
1988	28.0%	1.0%	7.8%	0.4%	2.6%	14.5%	0.01%	0.2%	23.4%			
1989	28.8%	1.0%	9.2%	0.4%	3.0%	15.5%	0.01%	0.2%	23.6%			
1990	29.6%	1.0%	10.3%	0.4%	3.5%	15.6%	0.02%	0.3%	23.8%	1.8%	1.2%	0.5%
1991	30.3%	1.0%	11.3%	0.5%	3.9%	15.4%	0.02%	0.4%	23.7%	6.9%	7.0%	1.8%
1992	30.9%	0.9%	12.3%	0.5%	4.3%	15.3%	0.02%	0.4%	23.8%	11.7%	14.3%	4.0%
1993	31.5%	0.9%	13.2%	0.5%	4.7%	15.0%	0.03%	0.5%	23.8%	16.3%	15.8%	6.0%
1994	32.0%	0.9%	14.0%	0.5%	5.2%	14.8%	0.03%	0.6%	23.9%	19.8%	18.9%	7.1%
1995	32.5%	0.9%	14.8%	0.6%	5.6%	14.5%	0.03%	0.7%	23.9%	22.3%	19.4%	7.3%
1996	32.9%	0.9%	15.5%	0.6%	6.0%	14.2%	0.03%	0.7%	23.9%	23.9%	19.5%	7.5%
1997	33.3%	0.8%	16.2%	0.6%	6.4%	14.0%	0.04%	0.8%	23.9%	25.4%	19.6%	7.7%
1998	33.6%	0.8%	16.8%	0.6%	6.7%	13.7%	0.04%	0.8%	23.9%	26.8%	19.7%	7.8%
1999	33.9%	0.8%	17.4%	0.7%	7.1%	13.4%	0.04%	0.9%	23.9%	28.1%	19.8%	8.0%

Source: TECo Conservation Plan, Docket No. 980737-PU, Feb. 12, 1990.

Exhibit ___PLC-11

Tampa Electric Company's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs

Year	Percent of New Sales Met with New DSM	Incremental Annual New DSM (GWh)	Cumulative DSM (GWh)	Cumulative DSM (MW)	Energy Savings as Percent of Sales	Peak Savings as Percent of Peak Load	Cum. Energy Savings Growth as Percent of Cum. Sales Growth	Cum. Peak Savings Growth as Percent of Cum. Peak Growth	Additional Cumulative DSM (GWh)	Additional Cumulative DSM (MW)
[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]
1991			142	190	1.0%	6.5%				
1992	25%	65	207	217	1.5%	7.0%	25.0%	16.8%	51	9
1993	30%	108	315	252	2.2%	7.9%	27.9%	24.4%	144	27
1994	35%	130	445	291	3.0%	8.9%	30.6%	28.6%	261	49
1995	35%	138	583	333	3.8%	9.8%	31.8%	31.3%	385	72
1996	35%	137	720	373	4.6%	10.7%	32.5%	32.9%	512	96
1997	35%	143	863	415	5.4%	11.6%	33.0%	34.2%	644	120
1998	35%	144	1,007	461	6.1%	12.5%	33.3%	35.4%	774	145
1999	35%	146	1,152	507	6.9%	13.4%	33.5%	36.5%	908	170
2000	35%	146	1,299	556	7.5%	14.2%	33.7%	37.5%	1042	195

Exhibit ___PLC-11

Tampa Electric Company's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs

Notes:

[1]: 1991 corresponds to 1991/92 peak, and so on.

[2]: Figure in 1994 and thereafter based on the expected energy savings achieved in collaboratively designed programs, with an adjustment for TECO's growth rate. (Collaborative data can be found in Exhibit ___PLC-6). The figures in the earlier years represent a judgement-based ramp-up period.

[3]: [2]*(annual growth in pre-C&LM sales)
Pre-C&LM sales = total sales to ultimate customers, plus energy conservation and load management.
Sales from TYSP, page II-22. C&LM from Need Determination Study, Table 3-2.

[4]: Cumulative sum of [3], plus TECO's planned 1991 DSM (from NDS, Table 3-2).
Note that 1991 includes only TECO's planned DSM.

[5]: [11]+(TECO's planned Winter conservation; from NDS, Table 3-2).
Note that 1991 includes only TECO's planned DSM.

[6]: [4]/(pre-C&LM sales)
See [3] for sales derivation.

[7]: [5]/(peak demand before C&LM)
Peak demnd = net winter peak demand (both firm retail and wholesale Sebring load, from NDS Table 3-1) plus Winter C&LM (from NDS, Table 3-2).

[8]: ([4] - [4] in 1991)/(Pre-C&LM sales growth from 1991)
See [3] for sales derivation.

[9]: ([5] - [5] in 1991)/(growth in peak demand before C&LM)
See [7] for peak demand derivation.

[10]: [4]-(TECO's planned Winter conservation; from NDS Table 3-2).

[11]: [10]*1000/(DSM load factor)/8760
DSM load factor = 61%. It is based on the weighted average of those of collaboratively designed programs (as derived in Exhibit ___PLC-6), and adjusted up by 20 percentage points to reflect the presence of TECO's separate load management programs.

Sources:

NDS: Tampa Electric Company (September 1991). "Polk Unit One Need Determination Study." Docket No. 910883-EI before the Florida Public Service Commission.

TYSP: Tampa Electric Company (April 1991). "Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines."

Exhibit ___PLC-12

Comparison of Tampa Electric Company's Current Resource Plan With a Resource Plan Utilizing Collaborative-Scale Conservation

Tampa Electric Company's Current Resource Plan (MW)

Year [1]	Peak Demand Before C&LM [2]	Load Management [3]	TECO Planned Conservation Resources [4]	Peak Demand After C&LM [5]	Supply Resources W/o Polk Unit One [6]	Polk Unit One [7]	Total Supply Resources [8]	Reserve Margin [9]
1991	2,925	174	190	2,561	3,232	0	3,232	26.2%
1992	3,088	180	208	2,700	3,307	0	3,307	22.5%
1993	3,179	186	225	2,768	3,489	0	3,489	26.0%
1994	3,278	193	242	2,843	3,489	0	3,489	22.7%
1995	3,382	199	261	2,922	3,489	0	3,489	19.4%
1996	3,481	205	277	2,999	3,489	150	3,639	21.3%
1997	3,584	212	295	3,077	3,489	220	3,709	20.5%
1998	3,689	218	316	3,155	3,489	220	3,709	17.6%
1999	3,794	224	337	3,233	3,489	220	3,709	14.7%
2000	3,902	230	361	3,311	3,489	220	3,709	12.0%

Collaborative-Scale Conservation Resource Plan (MW)

Year [10]	Peak Demand Before C&LM [11]	Load Management [12]	Collaborative-Scale Conservation [13]	Peak Demand After C&LM [14]	Supply Resources W/o Polk Unit One [15]	Revised Polk Construction [16]	Total Supply Resources [17]	Reserve Margin [18]
1991	2,925	174	190	2,561	3,232	0	3,232	26.2%
1992	3,088	180	217	2,691	3,307	0	3,307	22.9%
1993	3,179	186	252	2,741	3,489	0	3,489	27.3%
1994	3,278	193	291	2,794	3,489	0	3,489	24.9%
1995	3,382	199	333	2,850	3,489	0	3,489	22.4%
1996	3,481	205	373	2,903	3,489	0	3,489	20.2%
1997	3,584	212	415	2,957	3,489	75	3,564	20.5%
1998	3,689	218	461	3,010	3,489	75	3,564	18.4%
1999	3,794	224	507	3,063	3,489	75	3,564	16.4%
2000	3,902	230	556	3,116	3,489	75	3,564	14.4%

Exhibit ___PLC-12

Comparison of Tampa Electric Company's Current Resource Plan With a Resource Plan Utilizing Collaborative-Scale Conservation

Notes:

[1]: 1991 corresponds to 1991/92 peak, and so on.

[2]: (Net retail and Sebring winter peak demand) + (Conservation and load management).
Net winter peak demand, both firm retail and wholesale Sebring load, from Table 3-1.
Winter C&LM from Table 3-2.

[3]: Winter Load Management from Need Determination Study, Table 3-2.

[4]: Winter Conservation from Need Determination Study, Table 3-2.

[5]: [2]-[3]-[4]

[6]: (Total available capavity) + (Sebring units) - (Sale to TECO Power Services).
Total available capaity from Ten-Year Site Plan, page III-7, without the prospective additions after 1993.
Sebring units (49 MW) purchased 2/28/91 (Need Determination Study, page 42) and serve peak load beginning 1992.
Capacity sale to TECO Power Services is 145 MW beginning in 1993 (Need Determination Study, page 47).

[7]: From Need Determination Study, page 90.

[8]: [6]+[7]

[9]: [8]/[5] - 1

[10]: 1991 corresponds to 1991/92, and so on.

[11]: See [2] for derivation.

[12]: Winter Load Management from Need Determination Study, Table 3-2.

[13]: The conservation resources available to TECO, based on collaboratively designed programs, are derived in Exhibit ___PLC-11.

[14]: [11]-[12]-[13]

[15]: See [6] for derivation.

[16]: The revision of the Polk units' construction schedule, facillitated by the addition of collaborative-scale conservation, is described in the text.

[17]: [15]+[16]

[18]: [17]/[14] - 1

Sources:

Need Determination Study:

Tampa Electric Company (September 1991). "Polk Unit One Need Determination Study." Docket No. 910883-EI before the Florida Public Service Commission.

Ten-Year Site Plan:

Tampa Electric Company (April 1991). "Ten-Year Site Plan for Electrical Generating Facilities and Associated Transmission Lines."