Cabinet 5, Shelf 1

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF FLORIDA

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| In re: Petition of | ) | Docket No. 910759-EI |
| Florida Power Corporation | ) | |
| for determination of | ) | |
| need for proposed | ) | |
| electrical power plant | ) | Filed: Oct. 21, 1991 |
| plant and related | ) | |
| facilities - Polk County | ) | |
| Polk County Units 1-4 | ) | |

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

Resource Insight, Inc.
October 21, 1991

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# 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 County project proposed by Florida Power Company ("FPC" or "the Company") is necessary to meet the future needs of Florida ratepayers. My testimony focuses on whether FPC has adequately developed, considered, and integrated alternatives to the Polk County 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: FPC 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 FPC is unable to establish that the Polk County project is the least-cost option for meeting future demand for electric service. Specifically, FPC 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 FPC 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 the Polk County units at a lower overall cost than building and operating the Polk County project. Nor has it established that the acquisition of additional demand-side resources could not economically delay the need for Polk County generation into the next century.

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

A: Several deficiencies in FPC's demand-side planning belie the Company's assertion that it is aggressively pursuing "all available and feasible DSM measures."[1] These deficiencies include the following:

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[1]Direct Testimony of Allen J. Keesler, Jr., p. 5.

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

- FPC neglects large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, FPC 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, FPC's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- FPC'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 FPC?

A: To assess FPC's future need for capacity, I project the levels of DSM that could be reasonably expected if FPC developed comprehensive programs with the same intensity as those developed by collaboratives in other states. By the winter of 1998/99, I estimate FPC could increase the total peak-demand savings from DSM by 100 MW, or 5% of the approximately 2200 MW the Company projects in its 1991 integrated resource study (IRS).[2]

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[2] Of the 2,200 MW peak savings projected by FPC, approximately 1,800 MW or 80% are due to load management efforts. The 100 MW additional savings is net of assumed reductions to load management savings. Aggressive <u>conservation</u> programs are projected to increase the Company's <u>conservation</u> program savings by 460 MW, or 115%. However, I also assume that FPC's <u>load management</u> savings decrease by 360 MW, or 20%. Thus, <u>net</u> additional savings are 100 MW. Peak demand figures cited are for the 1998/99 winter peak and energy figures are for 1999.

FPC's intensified acquisition of demand-side resources could produce even larger increases in energy savings from DSM. By 1999, FPC's DSM programs could generate energy savings of 2,500 GWh/yr, more than a three-fold increase over the level contained in FPC's 1991 IRS (including savings from earlier programs). If we assume that Polk County operates at a 55% capacity factor, then the additional savings attainable are equivalent to the output of 380 MW or 41% of Polk County capacity.[3]

If FPC were to acquire these additional peak savings, then its capacity requirements would decrease by the equivalent of the first 235 MW Polk County unit. Thus, the project could be scaled back to 705 MW, with capacity first

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[3]According to FPC, the Polk County units will operate with an average 55% capacity factor, or 1,132 GWh for each 235 MW combined cycle unit. See the Integrated Resource Study, p. 84. Assuming a 150 MW CT (IRS, p. 292) operating at a 20% capacity factor (DSM Plan, February 12, 1990, p. C-7), or 263 GWh/year output, 869 GWh/year is attributable to the HRSG. Thus, the additional energy savings I project are equivalent to the output of over two heat recovery steam generators.

required in 1999/00.[4] More importantly, the magnitude of additional energy savings attainable might allow for a portion of the 940 MW of combined cycle capacity to be replaced by lower-cost combustion turbine capacity. Alternatively, these savings might allow the Company to pursue a phased construction schedule, initially installing combustion turbines and then adding heat recovery steam generators at a later 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 FPC 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 FPC's petition for a Determination of Need?

A: I would recommend that the Commission decline to approve the Company's proposal to build Polk County until the utility demonstrates (1) that it has undertaken to implement all economic energy

[4] A fourth unit might be added in 2002, replacing whatever resource FPC would otherwise have acquired.

efficiency and load management that could displace new power plants and (2) that the prposed new units in Polk County are still the least cost supply option available to meet any remaining requirements. But, regardless of the Commission's ultimate decision on FPC's application in this proceeding, it should reaffirm its directive in Docket No. 910004-EU that "FPC should be more aggressive in the areas of energy reducing ... programs" (p. 4) by directing the Company to improve its planning and acquisition of demand-side resources before it commits to the construction of the Polk County units. 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 and when they add or replace appliances and equipment. In addition, the Company should be directed to consider the Polk County units 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, FPC cannot establish that resource additions are prudent or likely to be used and useful in providing future service to ratepayers. FPC will be at risk for investments and operating costs, including fuel, incurred due to the inadequacies in its conservation programs.[5]

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

A: Section II examines the least-cost planning obligations FPC 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

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

-side resources systematically. I trace this failure to FPC's inadequate planning and design of demand-side programs. Section IV presents details of the improvements and expansion in demand-side resource acquisition that FPC 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 FPC should reasonably be expected to acquire through the end of this century. Finally, I present my conclusions and recommendations in Section V.

## II. FPC'S OBLIGATION TO PURSUE INTEGRATED RESOURCE PLANNING IN ORDER TO JUSTIFY A DETERMINATION OF NEED FOR THE POLK COUNTY PROJECT

### A. FPC's Application and Requirements of Florida Statutes

Q: Please summarize FPC's proposal.

A: FPC has applied for a Determination of Need for the construction of new generating facilities at a site located in Polk County. The Company proposes to install four generating units totalling 940 MW of capacity over a three-year period. The schedule of capacity additions associated with the Polk County project is shown in Exhibit __PLC-2. The Company's projected resource balance with and without the Polk County units is shown in Exhibit __PLC-3.

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 FPC met these requirements?

A: No. FPC has omitted an array of conservation resources from its resource plan and has failed to make a reasonable showing that no other cost-effective DSM alternatives to its Polk County units exist. Although the Company has recently expanded its efforts to acquire energy-saving efficiency resources, load management resources targeted to peak demand savings continue to dominate its conservation 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 County.

By failing to explore viable alternatives, FPC 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 FPC's application. At a minimum, failure by FPC 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 FPC to dismiss prospects for more comprehensive and flexible lower-cost options that may replace or delay the capacity FPC has proposed. As discussed below, FPC 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, FPC must show that it has exhausted the wide range of viable cost-effective demand-side alternatives**

Q: What must FPC establish to substantiate the need for Polk County?

A: The Company should have to establish that no combination of resources is available to meet the same need as the Polk County project for less than the projected cost of building and operating the project over its economic life. In other words, FPC must show that Polk County 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 County?

A: The objective of least-cost planning is to minimize the total system costs of providing adequate and reliable service. Integrated 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 explore viable alternatives, FPC 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 FPC's application. At a minimum, failure by FPC to develop and incorporate least-cost options should lead the Commission to place strict conditions on any approval it grants the Company.

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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.[6] But much of the demand being forecast by utilities arises because most

[6]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.

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 pursue only the most cost-effective DSM?

A: No. Least-cost planning requires utilities to pursue the most cost-effective <u>resource plan</u>. This goal implies that FPC should pursue <u>all</u> 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 FPC 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.[7]

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?

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

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

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, yes. 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.[8]

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 taken advantage of in the market. To make use of demand-side resources requires special programs, which try to

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[8]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.

> 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, FPC's 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.[9]

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[9] 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.

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

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, FPC 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 FPC 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. FPC'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.[10]

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

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[10] 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.

cost-effective efficiency measures for one reason or another, a multiplicity of barriers is likely to impede any class's exploitation of economically 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.[11] 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

[11]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.)

physical or institutional characteristics, may lose their cost-effectiveness unless actions are taken to develop these resources or to hold them for future use."[12] On the demand-side, lost-opportunity resource programs pursue efficiency savings that otherwise might be lost because of economic or physical barriers to their later acquisition.[13]

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 FPC's load growth, and thus actually create its requirement 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

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

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

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 facility expansion. Unlike any other option available to utilities, the acquisition of lost-opportunity resources will parallel the utility's resource needs.[14]

Q: Where are lost-opportunity resources usually

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[14]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.

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 remodelling or renovation; and
- when existing equipment either fails unexpectedly or is approaching the end of its anticipated useful life.[15]

As observed by Gordon, et al.:

[15] 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 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.

> 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.[16]

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 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)

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

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.[17] In Vermont, the Public Service Board and the utilities it regulates are making lost-opportunity resources a top

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[17] 1986 Northwest Plan, op. cit., at 9-28 through 9-30.

priority.[18] The Idaho Public Utilities Commission recently ordered utilities under its jurisdiction to submit a "Lost Opportunities Plan." [19] 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

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

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

> 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 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 FPC 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.[20]

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 not participate otherwise, and comprehensive

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

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.

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

A: More than any other utilities in the U.S., these companies 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-7 provides various measures of aggregate electricity savings for these collaborative DSM plans. To facilitate comparison with FPC, 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-7 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.[21] In terms of energy savings, these collaborative programs generate between 4% and 16% of total sales.

Exhibit __PLC-6 provides expected savings figures for 1991.

Q: How much are utilities with collaboratively

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

-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-5. 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-8 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). In comparison, FPC estimates its avoided costs to be approximately 8.1 cents/kWh at the 35% load factor of the NEES

1991 portfolio.[22]

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

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[22]All of these costs are stated in real-levelized dollars. To FPC's estimate of avoided cost, the Commission should add externalities, costs of Clean Air Act compliance, risk reduction, and marginal losses. Higher fuel inflation rates and capitalized energy may also be appropriate additions to the avoided costs.

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.[23]

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

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[23] 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.

> (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.)[24]

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

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[24] Nadel, S. and Tress, H., The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs, Final Report prepared for the New York State Energy Research and Development Authority and the New York State Energy Office. November 1990, p. 9.

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-9 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 also true for new construction and non-residential equipment replacement and building remodelling. 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 prior to the collaborative design process.[25] Yet nearly all NEES programs now cover 100% of measure

[25]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", Energy Program Evaluation: Conservation and Resource Management. 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," Energy Program Evaluation: Conservation and Resource Management. Chicago; August 1989, pp. 107-112.

costs.[26] The one notable exception to this rule is in the 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.[27]

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

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[26]See generally Power by Design: A New Approach to Investing in Energy Efficiency, 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.

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

-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?

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.[28] 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

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[28]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", <u>Energy Program Evaluation: Conservation and Resource Management</u>. Chicago; August 1989, pp. 365-371. Note the coincidence between higher participation and the more comprehensive set of measures offered to participants.

customer participation and achieve high measure penetration. Programs offering only partial incentives without individualized marketing and 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."[29]

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

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

participation rates. High incentives ... appear to promote greater participation than moderate incentives ... However, moderate incentives may not achieve higher participation than low incentives.[30]

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.[31]

Since the goal of least-cost planning is to

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

[31] Id., p. 181.

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.[32]

As Berry concludes:

> 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,

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

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. FPC has not determined where this might be possible. The Company will not be able to determine the "optimal" incentive until they have found 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 measures 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."[33] 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

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

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?

A: Other features of collaborative programs are summarized for four utilities in Exhibit __PLC-10. These programs follow the following general principles:

- <u>Target program delivery strategies and marketing approaches according to the decision-makers and types of investments involved.</u> 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.

- <u>Personal marketing is critical.</u> 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.[34]

- Avoid paying for "naturally-occurring" savings by maintaining high minimum efficiency thresholds. The higher the minimum efficiency criteria utilities set for program eligibility, the more net savings

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[34]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.

each program dollar buys, assuming equipment complying with minimum standards is widely available. Utilities often see dramatic proof of this principle.[35] 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

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[35] 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.

more complex programs appear to customers, the 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 walk-through 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. FPC HAS NOT ESTABLISHED THE NEED FOR POLK COUNTY BECAUSE IT HAS NOT EXHAUSTED LEAST-COST DEMAND-SIDE ALTERNATIVES TO POLK COUNTY

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

A: Thus far, FPC has under-invested in energy-saving demand-side resources. While the Company has continued its aggressive pursuit of peak demand savings with extensive load management efforts, it has failed to target economical <u>energy-efficiency</u> resources adequately. The scope, scale, and pace of FPC's planned acquisitions of demand-side resources are inadequate given the magnitude, composition, and timing of its supply commitments. As shown in Exhibit ___PLC-4, FPC's present commitments represent only 369 MW and 686 MWh from energy-efficiency resources through the year 1999. They account for only 8% of projected peak demand <u>growth</u>, and 3% of energy sales <u>growth</u>, through 1999.

Such small savings come as no surprise, given the relatively low levels of expenditures FPC plans for energy-saving DSM. Of the approximately $6 million FPC currently plans to spend per month on DSM programs, over 80% is budgeted for load management efforts.[36]

In sharp contrast to FPC'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

[36]Based on data provided in Exhibit 1, Schedule C-2 of the testimony of Company witness Cleveland in Docket No. 910002-EG.

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 FPC should be expected to produce an additional 100 MW and 1,900 MWh by the year 1999.

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

A: Because of the Company's inadequate approach and commitment to DSM, FPC has failed to establish that DSM cannot substitute more cost-effectively for some or all of the energy and capacity from Polk County. FPC's resource plans omit energy-saving demand-side resources that could be cost-effective compared to Polk County under the total resource cost test. Like leading utilities, FPC should fully develop and pursue <u>all</u> 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 FPC could add over Polk County's life represents a kW or kWh not needed from Polk County, at least on the current schedule.

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

A: FPC'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 County. This weakness is attributable to deficiencies and omissions in the Company's approach to program design and implementation. More specifically:

1. FPC fails to target DSM market sectors comprehensively. The Company omits essential sectors, end-uses, and measures. These omissions call into question FPC's screening process.

2. FPC's existing programs inadequately address market barriers. Customer incentives are too low, direct installation programs are not aggressive, and programs are fragmented. This will lead to cream-skimming.

3. FPC is not sufficiently ambitious. The Company has set its participation goals far too low.

4. FPC 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 FPC can achieve in the long run.

## A. FPC's Programs Are Not Comprehensive

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

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

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

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

- measures, most notably fuel-switching.

### 1. Missing Customer Sectors

#### a. Lost opportunities

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

A: FPC'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, FPC 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 FPC misses will be irretrievably lost; the Company will have to make up for these lost opportunities with more costly supply.

Q: How should FPC pursue lost-opportunity resources?

A: FPC should target programs to affect appliance replacement, new construction in the commercial and residential sector, commercial remodeling/renovation, and commercial and industrial equipment replacement. FPC should offer incentives for equipment whose efficiency exceeds current standards (either of law or practice). For example, FPC should pay the full incremental costs of high-efficiency motors where those motors are cost-effective. Section IV, below, summarizes the types of programs FPC should implement for each conservation market sector.

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

A: Yes. FPC's Trade Ally Program addresses both residential and commercial new construction and the residential and C/I HVAC Allowance programs seek to affect the efficiency of HVAC equipment being replaced.

Q: Is the Trade Ally program likely to maximize the cost-effective savings FPC can obtain from new construction?

A: No. The Trade Ally program has two major flaws. First, it only encourages builders to <u>meet</u> Florida standards, not exceed them. Second, it offers no financial incentives to builders to help cover the incremental cost of efficient design and equipment.

Q: What is wrong with encouraging builders to meet rather than exceed Florida standards?

A: Given that building efficiency standards are not met with high compliance in Florida, it is useful for FPC to encourage builders to comply with the standards. However, FPC should not limit its efforts to merely ensuring that buildings meet code. The Company should work to advance common practice by paying for measures or practices that <u>exceed</u> State standards.[37] This approach has been successfully employed by Pacific Gas & Electric with the evolution of California's Title 24 building standards. Well-designed programs aim for higher efficiency even in states where building codes are enforced. For example, both Boston Edison's and Northeast Utilities' new construction programs explicitly require projects to exceed building codes, and pay incentives for

[37]FPC has recognized that it can be cost-effective to beat the standards: to qualify for its Demand Reduction Capital Offset program, new construction projects must exceed standards by 25%, concerning infiltration, equipment performance criteria, and insulation values.

performance above code and standard practice.

As long as efficiency technology continues to advance, the Company's long-range resource planning should continually invest in a cycle of advancing common practice and raising standards. Because of their long-term nature and low incremental installation costs, there are many cost-effective new construction efficiency options beyond simply requiring a building to exceed standards. In addition to high-efficiency equipment, utilities can encourage the use of efficient building design (including daylighting), HVAC controls, occupancy sensors, and other innovative measures.

Q: What incentives does the Trade Ally program offer?

A: The program does not offer any financial incentives; it only "makes recommendations on equipment and building techniques" (FPC Energy Efficiency and Conservation Programs, or EECP, at J-2). The company also performs a blower door test on one model home in each development, followed up by explanations of how to fix the problems found and avoid them in the future. FPC estimates that this will cost $200 per model home or $25 per development home ($60 per development home, including administrative overhead, EECP at J-4).[38] FPC in no way ensures its more expensive recommendations will be carried out. This program is highly inadequate: as I have explained, incentives of 100% of incremental costs are essential to capture lost opportunity resources.

Q: What are the consequences of FPC's inadequate treatment of lost opportunities in the new construction sector?

A: By foregoing these resources, FPC denies its ratepayers significant cost-effective energy and capacity savings. It will be far more expensive, and in some cases, impossible, for FPC to reap savings from these resources once the window of opportunity (e.g., the construction process or the equipment purchase) has closed.

Q: What other lost-opportunity programs does FPC offer?

A: FPC's residential and commercial HVAC allowance

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[38] If FPC's program were well designed, it would sufficiently educate builders so that the blower door test would become superfluous, because builders would already know how to build to exacting thermal integrity standards.

programs target the HVAC replacement sector and new construction projects are eligible for the Demand Reduction Capital Offset (DRCO) program.

Q: Are these programs likely to be effective?

A: No. Neither of these programs pays adequate incentives, and the equipment eligibility thresholds for the HVAC Allowance are too low. In order to maximize the cost-effective savings obtained through lost-opportunity resources, these programs should pay the full incremental costs of the high efficiency equipment. FPC's incentives do not approach incremental costs.

Q: Please identify the weaknesses of the DRCO.

A: Though the DRCO is well-intentioned, it is not structured in a way that will effectively combat market barriers. The program is designed to encourage the installation of efficiency measures not addressed by other FPC programs. The DRCO covers retrofits as well as new construction, and requires that new construction projects exceed infiltration, insulation, and equipment codes by 25%. Unfortunately, the DRCO's incentive structure is self-defeating, and will prevent this program from maximizing cost-effective savings.

The program will pay only 25% of the total project cost.[39] As discussed above in the section on lost opportunities, this low incentive level is totally inappropriate for new construction projects. It is likely to be too low for retrofit projects as well.

This low incentive, coupled with the fact that "only projects with a simple payback to the customer of over two (2) years (after receiving the FPC incentive) will be considered" (EECP at T-2) will essentially guarantee poor program results. Most customers are unwilling to undertake efficiency retrofits unless the payback period is <u>less</u> than two years. Exhibit __PLC-9, which summarizes incentives paid in collaboratively-designed C/I programs, shows that none of these retrofit programs offers incentives that require more than a two year payback. Most of them offer incentives of 100% of incremental costs.

This program is also subject to three separate caps, which will further erode savings. First, rebates are limited to $25,000 per metered account. Second, there is a maximum rebate of

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[39] It is not clear how "project cost" is defined for new construction.

$150/kW reduction.[40] Third, the Company places a maximum limit of $300,000 per six-month cost-recovery period in rebate incentives for all projects in the program.

These caps will result in cream-skimming and in a higher proportion of free riders. Customers will opt not to pursue measures that are more costly, more difficult to implement, or are perceived as risky. They will instead implement only the cheapest, simplest, and most predictable measures.

Q: Can you give an example of the disparity between FPC's HVAC incentives and those of a utility that does pay incremental costs?

A: Yes. Northeast Utilities' C/I New Construction program determined that incremental costs for Central AC units were approximately $5 per 0.1 EER

[40]Note that by specifying a cap in terms of kW reduction, FPC is not taking into account measures' energy savings.

per ton above code or standard practice.[41] If it followed this guideline, using a baseline SEER of 10, FPC would pay an incentive of $500 for a 5-ton SEER 12 unit. FPC's incentives are a paltry (non-cash) $85 per unit.[42]

Q: Why are the minimum eligibility thresholds for the HVAC Allowance programs too low?

A: FPC's residential and C/I HVAC Allowance (as well as the residential loan program) demonstrate the same half-hearted approach to program design. The minimum qualifying seasonal energy-efficiency ratio (SEER) is 10 for heat pumps and 11 for central air-conditioners. Yet by January 1st,

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[41]Testimony of Earle F. Taylor on behalf of Western Massachusetts Electric Company for Pre-Approval of conservation and Load Management Programs, March 1991, p. II-39. Dr. Aleksandar D. Brancic, P.E., of Northeast Utilities' Conservation and Load Management department conducted a study that found incremental costs of C/I AC units were closer to $10 per tenth of an EER point above code (personal communication with Jim Peters, Resource Insight, Inc., 10/10/91).

[42]The incentive is given to the dealer in the form of a non-cash incentive based on earned points redeemable for merchandise.

1992, it will be illegal to manufacture heat pumps and air-conditioners with an SEER of less than 10 (See 10 CFR CH. II, Part 430, Subpart C, §430:32). In the case of heat pumps, FPC 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.

As for Central AC units, the HVAC Allowance (and residential loan) minimum SEER of 11 is slightly above the legal minimum standard of 10. However, FPC does not explain why it chose 11 as the minimum qualifying SEER rating. Central ACs with a minimum SEER of 11.5 or 12 would probably have been cost-effective.

Q: Are new construction customers eligible for the HVAC Allowance programs?

A: No. FPC has also made a truly puzzling decision regarding HVAC efficiency resources in new construction. It specifically excludes new construction from its HVAC allowance program (EECP at H-1), yet offers no HVAC incentives in the Trade Ally program. FPC has effectively eliminated all opportunities for savings from HVAC in new construction.

Q: Are there other sources of lost-opportunity savings that FPC is bypassing altogether?
A: Yes. Unfortunately, FPC has so far ignored the lost opportunities presented by residential appliance and water heater replacement, by commercial refrigeration, and by industrial process efficiency improvements.

### b. Lack of a Program for Low-Income Customers

Q: Does FPC offer any programs specifically designed for low-income customers?
A: No.
Q: Are low-income customers likely to participate in FPC's existing programs?
A: Eligible low-income customers are not likely to be able to participate in FPC's existing programs. Low-income households offer a classic example of 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 people 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 even 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.[43]

Q: Why should FPC 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 FPC's DSM programs. However, unlike other customers, low-income customers are not truly able to participate in any of FPC's existing programs. This raises problems of equity. In addition, helping to reduce low

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[43]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).

-income customers' consumption will help lower their bills. This in turn is likely to help lower FPC's uncollectible accounts.

### 2. Missing End-Uses

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

A: FPC fails to offer efficiency measures for the following end-uses:

Residential sector:

- improved efficiency in new and replacement refrigerators and freezers;
- lighting efficiency improvements via direct installation and point-of-sale programs of compact fluorescent lamps and fixtures;
- improved efficiency in appliances such as clothes washers and dryers, dishwashers, and electric ranges.

C/I Sector:

- all HVAC efficiency options for

commercial customers for the retrofit market;

- savings from chillers;[44]

- savings from high-efficiency commercial and industrial refrigeration.

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

3. **Missing Measures**

Q: Are there additional measures missing from FPC's plan, other than those you have already listed?

A: Yes. FPC has omitted measures that can offer substantial and long-lasting savings. These measures include:

- efficiency improvements beyond building code in new residential construction,

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

both single-family and multifamily;

- savings from comprehensive residential and C/I retrofits to reduce space-heating and space-cooling requirements;

- electric water heating efficiency improvements through more efficient equipment (except heat pump water heaters), and through cost-effective fuel-switching of new or replacement water heaters to natural gas;

- fuel-switching measures.

Q: Where is it evident that FPC neglects residential new construction measures that exceed code?

A: FPC's Trade Ally program does not offer incentives for exceeding code. FPC has no other program that addresses residential construction.

Q: How does FPC neglect savings from comprehensive residential and C/I space-heating and cooling retrofits?

A: FPC offers only a piecemeal treatment of residential and C/I thermal integrity measures, and its programs do not cover all relevant cooling and heating equipment.

Q: Where could a comprehensive treatment of water heaters fit in to FPC's programs?

A: FPC could offer incentives to dealers for selling high-efficiency water heaters, heat pump water heaters, and non-electric water heaters.

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

A: Fuel switching can produce large reductions in electric usage. Alternative fuels are often less expensive than electricity. 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.[45]

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

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[45]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.

been addressed for various applications and various fuels in the study I performed for Boston Gas in Mass. DPU 89-239 and DPU 90-261A,[46] in the work of several Vermont utilities, in the Bonneville Power Administration Resource Plan,[47] and in a Lawrence Berkeley Lab study for Michigan,[48] 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 have 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

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

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

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

gas, but the Vermont utilities also determined that conversion of residential space and water heating to oil and propane will often be cost-effective.[49] Thus, fuel-switching is not a particularly exotic or obscure DSM option. The technology is also well-developed.

4. **Measure and Program Screening Process**

Q: What suggests to you that FPC's measure and screening process might be flawed?

A: Though I do not have access to the inputs and outputs of all of FPC's program and measure screening, several elements of FPC's DSM programs suggest to me that the Company did not properly screen its measures and its programs.

I find it suspect that measures and programs that are integral parts of other utilities' DSM programs do not appear in FPC's programs. Examples of measures and programs that other utilities have found to be cost effective include:

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[49]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.

residential lighting, appliance efficiency programs, and residential and C/I new construction programs that seek to "beat the standards".

Other elements unsubstantiated in the EECP raise further questions about FPC's screening process. The low eligibility thresholds for equipment, the low incentive levels, and the emphasis on load management suggest that FPC is improperly screening its measures and programs.[50]

Q: How should FPC be selecting measures?

A: To avoid cream-skimming and maximize achievement

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[50]On page 233 of its IRS, FPC reports the GWh <u>increases</u> due to its marketing programs, mostly from its industrial and commercial economic development plans. These increases are of the magnitude of over 80% of the Company's savings from its conservation plans. As the IRS does not provide any description of these marketing programs, or of their cost-effectiveness, I cannot evaluate their role in FPC's integrated resource plan. FPC should tie any economic development incentives to the implementation of energy-efficient designs and the installation of energy-efficient equipment, and provide development incentives proportional to employment or investment, rather than to electric use.

of cost-effective efficiency savings, FPC should follow these steps:

1. Start by targeting market sectors, not end-uses;

2. Identify the set of measures likely to apply to customers in that sector, and screen them in combination;

3. Optimize those measures to maximize the net benefits from measures installed for typical customers in that market segment;

4. Estimate delivery costs of the program targeting installation of the optimized measures set, and screen the program to see if net benefits are sufficient to cover measure and non-measure costs.

Q: Does FPC use the no-losers test to limit its investment in cost-effective demand-side resources?

A: I am unable to ascertain from the documents filed in this proceeding if FPC rejects conservation measures or programs based on the results of the RIM test. Of the 22 programs the Company has included in the EECP, only 3 fail the no-loser's test. This strikes me as odd. It seems possible that FPC used the rate impact measure test to screen programs. I also expect that if FPC had reflected externalities in its screening process, additional programs and measures would have been found cost-effective.

Q: Does FPC incorporate environmental externalities in its economic evaluation of demand-side resources?

A: No. Company witness Gelvin testified, however, that a recent rule change relating to externalities will not "materially affect the cost-effectiveness findings for M.A.C.S. programs..." (Gelvin, at 12)

Q: Do you agree with the implication in Gelvin's testimony that including externalities should not affect program cost-effectiveness?

A: No. While including externalities in avoided costs will not lead to the screening out of existing programs, it might lead to the screening <u>in</u> of programs not currently judged cost-effective. Gelvin fails to acknowledge that higher avoided costs reflecting externalities should increase the magnitude of economical demand-side savings, as more expensive DSM resources become cost-effective under higher avoided costs.[51]

B. Inadequacies of FPC's Existing Programs

Q: What are the major inadequacies of FPC's existing programs?

A: FPC's programs are characterized by

- insufficient incentives;
- inadequate direct delivery programs; and
- a fragmented treatment of DSM market sectors.

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[51]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 its current DSM activities; nor does it model strategies that include intensified DSM as an alternative to scrubbing or fuel switching. See generally the Integrated Resource Strategy, pp. 121-123.

1. **Insufficient Incentives**

Q: Are FPC's incentives likely to be effective in combatting market barriers?

A: No. FPC's incentive structure has three flaws that act in concert to prevent the Company from obtaining all cost-effective conservation resources. These flaws are that:

- FPC's incentives never cover more than half of measure cost;
- incentives are capped; and
- incentives are not indexed to equipment efficiency.

Q: Why should FPC 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 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).[52]

Q: Please give examples of FPC's incentive caps.

A: FPC's sets low caps on its financial incentives. For example:

- the residential AC tuneup incentive is a coupon for $5;[53]

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

[53]United Illuminating offers a much higher incentive, $25, towards the cost of a tuneup. Personal communication with Dave Cawley, Vermont Energy Investment Corporation (10/11/91).

- the C/I Blower Door program will pay part of the cost of an inspection and repairs, up to $125;

- the maximum allowable rebate in the Indoor Lighting Incentive is $100/kW saved;

- the C/I HVAC Tuneup offers a coupon for $5 towards the cost of a tuneup;

- the C/I Fixup program will pay one half of the contractor's billed price, up to $100;

- the DRCO rebate is capped at $150/kW.

Q: How do FPC's incentives compare to its avoided costs?

A: FPC's estimate of the present value of avoided demand-related costs per kW is $1,453/kW ($963/kW for generation, plus 15% reserves, $98/kW for transmission, and $248/kW for distribution). The present value of the estimated energy-related avoided costs range from $600/kW for low-load

-factor programs (e.g., the Residential Blower Door program) to over $3,000/kW for high-load-factor programs (e.g., DRCO.) Thus, incentives are typically capped at 3-5% of avoided costs.

Q: What consequences might one expect from FPC's incentive caps?

A: FPC's incentive caps are likely to discourage precisely those customers whose larger retrofits offer greater opportunities for savings. The caps might lead to lower participation rates, which in turn will limit the amount of cost-effective conservation the Company acquires. The caps might also lead to customers downsizing their efficiency projects. Customers would cream skim by eliminating the more costly measures from their projects.

Q: What are the consequences of offering fixed incentives for equipment replacement?

A: FPC's incentive structure for HVAC replacement is fixed, regardless of the equipment's efficiency. This sets the stage for customers to cream-skim by buying the least expensive equipment. The company provides no motivation for a customer to buy a Central AC with a SEER of, for example, 12, rather 11. Many utilities have avoided such cream

-skimming by indexing incentives to the equipment efficiency. In other words, higher-efficiency equipment receives a proportionally higher rebate. The indexed rebate system encourages customers to purchase the most efficient cost-effective equipment available.

Q: How should FPC determine how much to pay for program measures and how much participants should pay for those measures?

A: FPC 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, FPC 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. FPC should not arbitrarily refuse to pay for the full incremental cost, if that is the most effective and efficient means of securing those improvements.

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. Inadequate Direct Delivery Programs

Q: Why should FPC offer direct delivery programs?

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 FPC will acquire.

Q: Does FPC offer direct delivery programs?

A: Yes, FPC offers the residential and C/I Fixup programs, in which the Company arranges for a contractor to install certain simple, low-cost efficiency measures. FPC will pay up to half the cost of the measures, subject to a $75 cap for residential and a $100 cap for C/I. However, to be eligible for a direct delivery program, a customer must first participate in one of FPC's audit programs. The time required for participating in this two-step process is likely to turn customers away from FPC's programs. The fact that the customer must pay at least half of the cost of the Fixup is also likely to decrease participation.[54]

For many measures, FPC should offer direct design and/or installation services.[55] 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.

[54]The customer not only has to pay for most of the contractor's fee, but also must review the contractor's proposal to ensure that the contractor performs only work for which the customer is willing to pay.

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

**3. FPC's Fragmented Treatment of DSM Market Sectors**

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

A: FPC makes the mistake of equating individual measures with "programs." Rather than proceed measure by measure in its pursuit of cost-effective conservation savings, FPC should proceed sector by sector, seeking to acquire all cost-effective savings available from a full set of measures applicable from each customer's facilities. FPC's piecemeal strategies will inevitably raise costs, reduce savings, and delay results.

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

A: FPC's DSM program portfolio includes a number of programs that offer a single measure. These programs are, for the Residential sector:

- the Blower Door/Air Conditioning Duct and Repair program, which targets leaks in AC ducts;
- the Insulation Upgrade program, which

upgrades ceiling and attic insulation; and

- the Air Conditioning Tuneup program, which offers a discount coupon for an AC tuneup.

In the C/I sector, there are five single-measure or single-end-use programs:

- an AC Service program offering AC tuneups;
- an AC Duct Test and Repair program;
- an Interior Lighting Conversion program;
- a Motor Replacement Rebate program; and
- a Heat Pipe Development program.

Q: What problems does this fragmented approach cause in the C/I sector?

A: In certain cases it is appropriate to offer single end-use C/I programs. Efficiency improvements related to lighting or motors may be sufficiently self-contained so that a single-end-use program would not lead to lost savings. However, FPC would be able to acquire more savings if it restructured its three HVAC programs into a single program that comprehensively targets the efficiency of a building's HVAC system. Currently, a customer must participate in three separate programs (C/I HVAC Allowance, C/I HVAC Tuneup, C/I Blower Door) to benefit from FPC's HVAC measures. This leads to cream-skimming: customers who do not want to hassle with all three programs will only participate in the simplest (or cheapest) program. FPC loses the savings from the measures in those HVAC programs the customer rejected. FPC also incurs higher administration and delivery costs.

Q: What difficulties arise due to the piecemeal assortment of residential programs?

A: A customer seeking to improve home energy efficiency may have to resort to participating in as many as 6 programs. Consider a customer who, upon learning of FPC's programs, decides to improve the efficiency of her home by insulating the attic, wrapping the water heater, tuning up the A/C, and fixing the leaks in the A/C ducts. This customer would also like to benefit from load management discounts. This well-intentioned customer would have to participate in six separate programs. First, the customer needs to arrange for FPC to perform a Home Energy Check or Home Energy Analysis to confirm that cost-effective energy-efficiency improvements can be made. Second, the customer must apply for the Home Energy Fixup program in order to have the water heater wrapped.[56] To have the A/C tuned, the customer needs to participate in a third program, the Air Conditioning Service. Through a fourth program, the Air Conditioning Duct Test and Repair, the customer can get the ducts repaired.[57]

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[56]The Home Energy Fixup program addresses several end-uses. It pays half the cost (up to $75) for installing window and door caulking and weatherstripping, door sweeps and thresholds, water heater measures, electrical outlet gaskets, and attic access insulation. It does not appear to use a blower door to identify cost-effective infiltration control options.

[57]The Air Conditioner Service and Air Conditioner Duct Test and Repair require AC system testing.

Getting the attic insulated requires a fifth program, the insulation upgrade.[58] To receive the load management discounts, the customer must participate in a sixth program.

Q: How will this piecemeal approach affect participation rates?

A: Customers are likely to be reluctant to participate in multiple conservation programs. This is because of the many inconveniences that accompany participating in programs, especially those structured as are FPC's. Participation involves spending time filling out forms and staying home to wait for and watch over contractors. In most programs, customers will have to review every contractor-proposed measure. This increases the burden on both parties, and thus the cost of the program. Many of the market barriers (inconvenience, information requirements, risk, cost) will not be overcome by this approach. They are not likely to follow through on the audits' recommendation for additional programs. The resulting lowered participation rate prevents

[58]Note that both the Air Conditioner Duct Test and Repair and Attic Insulation may require working in the attic.

FPC from maximizing cost-effective savings.

Q: What is wrong with the Company's approach as you have characterized it?

A: In the programs discussed above, FPC passes up opportunities to bundle measures. Bundling measures would lower the overall cost of FPC's DSM portfolio by removing single-measure programs and replacing them with an umbrella program. It would increase the amount of savings FPC can expect from each customer visit. It would also likely increase participation: customers are more likely to participate in a program that offers several measures than in a single-measure program. The result of FPC's lack of comprehensiveness is cream-skimming. Three consequences of this approach are antithetical to least-cost planning. First, FPC's piecemeal approach will reduce the levels of savings the Company can achieve. Second, it will raise the costs of the savings it does achieve. These two consequences are a result of the Company's failure to "bundle" measures that would be cost-effective: the Company renders additional savings uneconomic because the fixed costs of subsequent customer treatment becomes prohibitive. Third, it will unnecessarily delay the acquisition of demand-side resources, thereby preventing such resources from reducing FPC's supply costs.

Q: Can you provide examples of how FPC's approach leads to cream-skimming?

A: 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." FPC does not use this approach in its programs and this leads to cream-skimming.

For example, the water heater control in FPC's Residential Load Management Program appears to be completely isolated from other water-heating measures, let alone measures for other end-uses. Before FPC 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 FPC finds that controlling the water heater is not cost-effective, all the efficiency improvements are still likely to be cost-effective. While FPC 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., below.

**C. FPC's DSM portfolio places undue emphasis on peak savings**

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

A: On page 48 of its IRS, FPC writes that "the residential load management program has been at the core of Florida Power Corporation's demand-side management programs." A quick qualitative overview of FPC'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. For example, out of a total six-month DSM budget of $34,633,131, FPC devotes $29,902,857, or 86%, to the load management program.[59] An analysis of FPC's MW and GWh savings confirms that indeed, FPC'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 FPC's DSM resources are devoted to peak savings?

A: I determined the load factor of FPC's DSM portfolio as outlined in Exhibit __TJG-4 of Gelvin's testimony. The load factor is calculated as:

GWh saved/(MW saved*8.760).

FPC's DSM programs have a collective load factor of 3%.

Q: How does this load factor categorize FPC'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 FPC's demand-side resources reveals that they do not

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[59] FPC budget figures for October 1991 - March 1992; figures provided in exhibit PDC-1 of P.D. Cleveland's testimony in FPSC docket No. 910002-EG.

even provide as much peak energy as their avoided peaking unit. In its input data for cost-effectiveness determination (see for example, EECP at G-7), FPC notes that its avoided peaking unit has a capacity factor of 20%. Thus, load management may not fully replace CT capacity, MW for MW.

Q: Is the 3% DSM load factor appropriate, given FPC's capacity and energy needs?

A: No. With their 3% load factor, FPC's DSM resources act as a peaking plant, and a rarely-used one at that. FPC's next avoidable unit, Polk County, is not a peaking plant. On the contrary: FPC anticipates running Polk County as an intermediate plant with a 55% capacity factor, and notes that the Polk County units "have the ability to run base load (continuous duty) as required" (IRS at 84).

FPC is investing in a "DSM peaking plant" while at the same time requesting to build intermediate/baseload power. FPC should also be acquiring a "DSM intermediate/baseload plant," including high levels of energy savings, both on- and off-peak.

Q: Why else might FPC 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), and consistently reduce requirements for the generation, transmission, and distribution capacity;are more durable, and do not involve service degradation. Efficiency resources are particularly valuable because:

- FPC's generation costs are more related to energy than to peak: the cost of fuel and of Clean Air Act compliance figure prominently in FPC's explanation of the advantages of Polk County (IRS at 84).

- 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.

D. Unambitious Plans

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

A: As shown in Exhibit __ PLC-11, FPC's own participation figures reveal that the Company has set very low participation goals for its DSM programs. Participation is lowest in precisely those programs that offer substantial opportunities for savings, i.e., the programs that follow the audits. By 1999, the audits are projected to draw a participation of 48.1% for residential and 49.6% for business. The follow-up Fixup programs have participation rates of 18.47% for residential and 0.61% for business. Participation figures for other programs are around 2% or less. These minuscule participation rates reveal that FPC is just playing around the edges of true least-cost planning. The company does not even purport to be maximizing its DSM resources.

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

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

A: Yes. As I show below, FPC 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 FPC's current plans and those of utilities with collaboratively-designed DSM programs, I find that FPC could acquire an additional 262 MW and 2,082 MWh in annual savings from cost-effective DSM by the year 1999. These additional savings will only be achievable if FPC 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 FPC's current resource plans and which the Company should pursue now?

A: Based on the portfolios of programs being sponsored by other utilities with collaborative-designed programs, FPC should develop and implement programs that pursue all cost-effective efficiency savings from the following market sectors:[60]

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

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[60]FPC's programs may already serve discrete segments of these market sectors. However, the Company's program strategy fails to target each and every market sector with distinct delivery mechanisms explicitly and systematically.

- Direct investment for small commercial customers

- Focusing on all cost-effective lighting retrofits

Residential:

- Residential new construction

- Residential comprehensive retrofit

    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 FPC'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, FPC's approach inappropriately treats an end-use or technology separately, generalizing the measure to an entire customer group.

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

A: A precise answer to this question will have to wait until FPC 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 FPC 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 FPC should be able to obtain?

A: Using the plans of utilities with collaboratively-designed programs as a guide, I estimate that FPC should be able to acquire an additional 459 MW of cost-effective demand savings from further <u>conservation</u> investment by 1998/99. I present these projections in Exhibit __PLC-12. However, I also assume that as a result of this additional conservation resource acquisition, load management efforts will yield 80% of the savings currently projected by the Company. Thus, <u>net</u> additional savings will be 102 MW in 1998/99. Including the Company's current plans for conservation and load management, FPC's total demand-side savings should be over 2,260 MW by the year 1998/99. These totals represent 23% of 1998/99 peak demand. By comparison, the Company's current plans account for 22% of 1998/99 peak load.[61]

Q: Why did you reduce the Company's projection of load management peak savings by 20%?

A: Adoption of additional efficiency measures may make some currently-assumed load management applications either impractical or uneconomical. Even if the load management application continues to be cost-effective, it may yield less savings when installed in conjunction with a conservation measure. For example, a water heater wrap may reduce the peak savings attainable with direct load control of the water heater.

I am unable to estimate the magnitude of this effect, as FPC has failed to document its load management projections. Thus, I have judgementally assumed that load management savings will be lowered by 20%.

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

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[61]All peak and energy savings figures cited are exclusive of reductions attributable to customer self-generation.

project?

A: Yes, there are. By the year 1998/99, my demand-side resource projections include 2,538 GWh of energy savings, representing 7.2% of total sales. These energy savings levels would be more than three times those included in FPC's current plans, which account for only 2% of total energy sales.

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

A: By incorporating my estimate of additional peak demand savings in the loads and resource balance projected for FPC, it is clear that the additional DSM would have a noticeable impact on the need for Polk County to meet projected peak demand. This is shown in Exhibit __PLC-13, which restates the Company's capacity and load position originally shown in Exhibit __PLC-3.

With the additional demand savings, the first 235 MW of Polk County installed in 1998/99 is no longer required to maintain a 15% reserve margin. Starting in 2001/02, when FPC expects to add its next plant, this Polk County unit could provide the additional capacity required.

Q: How would the additional energy savings you project influence the economics of combined-cycle technology for the Polk County 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 probably influence the fuel-cost savings associated with the Polk County project by reducing the marginal energy costs on FPC's system. This effect may be large enough to either replace portions of the combined-cycle capacity with simple-cycle combustion turbines, or to phase in the combined-cycle component by first installing CTs and then adding the heat recovery steam generators at a later time.

Q: How did you estimate future energy and peak demand savings from a comprehensive portfolio of FPC DSM programs shown in Exhibit __PLC-12?

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 FPC'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 FPC's DSM programs, I then added these annual energy acquisitions to the 1991 DSM energy savings projected by FPC in its IRS.[62]

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

Q: How did you arrive at the annual percentages you applied to FPC 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 Exhibit __PLC-7. For residential programs, these plans indicate a range of DSM

[62]Total savings are for conservation resources only. Thus, all figures exclude FPC's projections for load management, heatworks, and voltage reduction.

energy savings of between 8% and 72% of cumulative sales growth. From these plans, I projected that mature FPC DSM programs could generate energy savings equal to 25% of new (post-1991) growth in residential energy sales.[63] I allowed three years for program ramp-up by starting FPC's residential

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[63]The simple mean of these relative shares is 35% for the six utilities' residential programs for which sufficient information was available. Weighted according to projected energy sales for the respective utilities, the residential savings amount to 55% of projected residential energy sales growth. The midpoint of these averages is 45%.

Although FPC's sales growth is double the growth expected for these utilities, I would expect absolute savings to be less than those estimated using the 45% 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 doubling of load growth will increase total savings by only 20%. To reflect this relationship between load growth and total savings growth, I reduced the 45% figure to 25%.

DSM energy savings at a rate of 15% of projected annual sales increases in 1992. I increased this fraction to 20% in 1993 and to 25% from 1994 to 2002. The result in each year is the incremental energy savings that FPC should be able to obtain with appropriately comprehensive programs for the residential class.

I followed the same basic procedure for the non-residential classes. For these customers, Exhibit __PLC-7 suggests that utilities with collaboratively-designed programs plan to save between 31% and 81% of cumulative growth in sectoral energy sales. For a mature FPC DSM portfolio, I chose to apply 30% to incremental annual energy sales.[64] As I did with the residential class, I allowed time for program ramp-up. In this case, however, I assumed that it would take four years for commercial programs to

[64]Both simple and weighted averages of non-residential programs for the six utilities indicate that such programs are planned to save 50% of new non-residential sales. Again, I reduced this figure to 30% to account for higher sales growth in FPC's C/I sector.

reach their full annual potential savings.[65] As shown in Exhibit ___PLC-12, I assume that FPC's programs will start out in 1992 by saving 10% of incremental sales. This percentage rises to 20% in 1993, to 25% in 1994, and to 30% for the years 1995-2002.

Taken together, my projections imply that FPC should meet between 20 and 25 percent of cumulative energy sales growth with DSM between 1992-2002, a fraction that is well within the range of plans by utilities with collaboratively-designed DSM portfolios shown in Exhibit __PLC-7. These savings should be accomplished for costs comparable to those which utilities are incurring for efficiency savings from collaborative programs shown in Exhibit __PLC-8, as discussed previously in Section II.

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

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[65]This reflects, for example, the longer lead time for new commercial buildings. Developers of new commercial buildings may participate in a FPC program in 1992, but the buildings themselves will not use electricity for another 18 months.

A: I developed the DSM load factor to apply to the additional DSM energy savings on the basis of the DSM plans of four utilities with collaboratively-designed programs for which I was able to obtain class-specific projections of energy and demand savings.[66] I developed these load factors by calculating the weighted average DSM load factor for the residential and non-residential classes from the DSM plans of BECO, EUA, NU, and UI.[67] The average is 58% for residential savings, and 42% for C/I programs. This compares to 16% for FPC's residential "conservation" programs and 32% for its C/I programs.

I reduced these weighted average load factors by approximately 30% to reflect the fact that FPC's system load factor is roughly 70% of the

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[66]Two of the utilities on which I relied for projecting energy shares did not have class-specific peak-savings projections.

[67]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-7. This quantity was multiplied by 1,000 and divided by 8,766 hours/year.

system load factors for the four utilities with collaboratively-designed programs. Thus, I used a 40% load factor for the residential savings and 30% for C/I savings.

V. CONCLUSIONS AND RECOMMENDATIONS

A. Conclusions

Q: Summarize your conclusions with respect to FPC's resource planning and the need for Polk County capacity.

A: While FPC has identified a need for additional resources towards the end of this decade, it has not established that Polk County is the best alternative for meeting this need. On the contrary, FPC 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 FPC has failed to include in its resource plan constitutes Polk County capacity and energy that FPC does not need, at least on the current schedule.

Q: If FPC needs capacity and energy resources by the latter half of the decade, why should the

Commission conclude that the Polk County project is not needed to meet these requirements?

A: To conclude that Polk County 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 County.

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

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

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

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

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

- FPC is neglecting large and inexpensive but transitory opportunities to save electricity in all customer classes. By failing to act to capture these valuable opportunities, FPC 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, FPC's partial treatment of individual customers through piecemeal programs will actually create lost opportunities.

- FPC'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 FPC's demand-side resource planning.

A: FPC's approach to DSM planning must be improved if the Company's resource planning is to be truly integrated, and if the Commission expects FPC to deploy a least-cost resource portfolio. Correcting this approach should enable FPC to meet about 25% of its energy sales growth with additional demand-side acquisitions. This translates into additional demand-side savings of about 100 MW and 1,900 GWh through the year 1998/99.

FPC 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, FPC 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, FPC should pursue all cost-effective lost-opportunity resources as quickly as administratively feasible.

**B. Recommendations**

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

A: I would recommend that the Commission decline to approve the Company's proposal to build Polk County 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 new units in Polk County are still the least cost supply option available to meet any remaining requirements. But, regardless of the Commission's ultimate decision on FPC'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 County units.

Q: Why should the Commission require FPC to reform its integrated resource planning before acquiring the Polk County project?

A: Unless FPC reforms its planning efforts, the demand-side resources generated by its approach to program design will be unnecessarily small, slow, and expensive. Consequently, FPC 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 County or any other major supply option.

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

A: The Commission should direct FPC 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, FPC should immediately target lost opportunities arising in new construction and in equipment replacement.

Specific details of how FPC 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 FPC'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 FPC to follow in the future?

A: I strongly urge the Commission to direct FPC 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 FPC'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 County plant does not start until FPC 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.[68]

One option is for the Commission to reject FPC's petition for a Determination of Need for the Polk County project, while indicating that the plant would be viewed more favorably once FPC 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 County site and any new gas pipeline required to supply the facility.

Alternatively, the Commission could issue a provisional determination for all or part of the Polk County project, conditioned on the Company meeting (in a future proceeding) the two

[68] I will assume for the purposes of this discussion that the Commission finds that Polk County will be an appropriate choice for intermediate/baseload capacity when that is needed. I have not examined FPC's supply alternatives.

requirements listed above.

In addition, the Commission could signal its intent to link Polk County 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 FPC has not yet developed before committing to the Polk County 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 County capacity.

Q: Are you recommending that the Commission direct FPC 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 FPC 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 FPC's service area.

Q: Is it reasonable and prudent for FPC to plan for the contingency that it will need additional power in 1998/99 or beyond?

A: Yes. In addition to developing contingency plans for adding resources to the system in 1998/99, FPC should also be developing strategies for minimizing the lead-time necessary to acquire resources when they are required or become cost-effective. However, planning to develop the resource is not the same as committing to acquisition 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, FPC should be planning and acquiring all demand-side resources that are less expensive than the Polk County project.[69] With additional demand-side resources in its resource portfolio, the Company may find that its deadline

[69]As affirmed in Florida Statute, the Company should also be acquiring all renewables that are less expensive than Polk County. (§ 366.81)

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 and pipeline supply, 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 County site and additional pipeline capacity?

A: By moving to secure and prepare the site, as well as gas supply for the site, the Company acquires the <u>option</u> to build on that site. 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 FPC plans to use the land to install capacity in addition to the combined-cycle units planned for 1998/99 to 2000/01. In fact, Company plans call for eventual development of 3000 MW of capacity on the Polk County site.[70]

Q: Can such an option-to-build strategy also be applied to new gas pipeline construction?

A: Yes. As noted by Company witness Watsey, only two years should be required for actual construction of a pipeline to serve Polk County. The Company need not commit to building the pipeline for several years, during which time it can continue the more lengthy and critical permit and authorization process.[71]

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[70]Direct testimony of Eric G. Major, p. 3.

[71]Nor does FPC need to commit to a gas supply contract immediately. In fact, Major notes the Company will probably not sign a contract until receiving site certification. (Gelvin, p. 8)

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

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% |

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

that requires a 20-year supply project to yield a 6-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

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 Table162% | |
| **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% |

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 might require on efficiency investments. Suppose a new home builder and FPC 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. FPC 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 FPC 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 FPC's perspective. Her decision would force FPC 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 FPC can do to get the low-E windows and other measures into the house is cost-effective as long as the measures (and FPC's administrative costs) are less than 6 cents/kWh.[72]

Q. In general, what are the consequences when market

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

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 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;[73]

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.

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

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.[74] 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

[74] 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.

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 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 <u>diversification</u> in its demand-side resource portfolio. Specific risks that tend to raise consumers' required return include the following:

<u>Financial risk</u>: 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.

<u>Technological risk</u>: 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.

<u>Market risk</u>: 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-1

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## PROFESSIONAL EXPERIENCE

***President, Resource Insight, Inc.***
*August 1986 - present*

Consulting and testimony in utility and insurance economics. Reviewing utility supply planning processes and outcomes: assessing prudence of prior power planning investment decisions, identifying excess generating capacity, analyzing effects of power pool pricing rules on equity and utility incentives. Reviewing electric utility rate design. Estimating magnitude and cost of future load growth. Designing and evaluating electric, natural gas, and water utility conservation programs, including hook-up charges and conservation cost recovery mechanisms.

Determining avoided costs due to cogenerators. Evaluating cogeneration rate risk. Negotiating cogeneration contracts. Reviewing management and pricing of district heating system.

Determining fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determining profitability of transportation services.

Advising regulatory commissions in least-cost planning, rate design, and cost allocation.

***Research Associate, Analysis and Inference, Inc.***
*May, 1981 - August, 1986 (Consultant, 1980-1981)*

Research, consulting and testimony in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions.

Consulted on utility rate design issues including small power producer rates; retail natural gas rates; public agency electric rates, and comprehensive electric rate design for a regional power agency. Developed electricity cost allocations between customer classes.

Reviewed district heating system efficiency. Proposed power plant performance standards. Analyzed auto insurance profit requirements.

Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

***Utility Rate Analyst, Massachusetts Attorney General***
*December, 1977 - May, 1981*

Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination and briefing. Provided extensive expert testimony before various regulatory agencies.

Topics included: demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power pool operations, nuclear power cost projections, power plant cost-benefit analysis, energy conservation and alternative energy development.

## PROFESSIONAL AFFILIATIONS

Senior Associate, Cambridge Energy Research Associates, Cambridge, Massachusetts.
Associate, Rocky Mountain Institute Competitek Service, Old Snowmass, Colorado.
Member, International Association for Energy Economics, and past Vice-President, New England Chapter.
Member, Association of Energy Engineers, Lilburn, Georgia.

## EDUCATION

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978.

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974.

## HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

## OTHER HONORS

Institute Award, Institute of Public Utilities, 1981.

**PUBLICATIONS**

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Utility Regulation," External Environmental Costs of Electric Power: Analysis and Internalization. Springer-Verlag; Berlin: 1991.

Chernick, P. and Schoenberg, J., "Determining the Marginal Value of Greenhouse Gas Emissions," Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II, July 1991.

Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs," in Proceedings from the Demand-Side Management and the Global Environment Conference, April 1991.

Caverhill, E. and Chernick, P., "Accounting for Externalities," Public Utilities Fortnightly, Vol. 127, No.5, March 1, 1991.

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Chernick, P. and Caverhill, E., "Monetizing Environmental Externalities in Utility Planning," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P., Espenhorst, E., and Goodman, I., "Analysis of Residential Fuel Switching as an Electric Conservation Option," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Ottinger, R., et al., Environmental Costs of Electricity, Oceana, September 1990.

Plunkett, J., Chernick, P., and Wallach, J., "Demand-Side Bidding: A Viable Least-Cost Resource Strategy," in Proceedings from the NARUC Biennial Regulatory Information Conference, September 1990.

Chernick, P. and Caverhill, E., "The Valuation of Environmental Externalities in Energy Conservation Planning," in Proceedings from the ACEEE 1990 Summer Study on Energy Efficiency in Buildings, August 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Evaluation of District Heating Options," in Proceedings from the International District Heating and Cooling Association 81st Annual Conference, June 1990.

Chernick, P. and Plunkett, J., "A Utility Planner's Checklist for Least-Cost Efficiency Investment," in Proceedings from the Canadian Electrical Association Demand-Side Management Conference, June 1990.

Chernick, P. and Caverhill, E., "Incorporating Environmental Externalities in Utility Planning," Canadian Electrical Association Demand Side Management Conference, May 1990.

Chernick, P., "Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?" in Proceedings of the NARUC Second Annual Conference on Least-Cost Planning, September 10-13, 1989.

Chernick, P., "Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities," in Least Cost Planning and Gas Utilities: Balancing Theories with Realities, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23, 1989.

Plunkett, J. and Chernick, P., "The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal," in Summer Study on Energy Efficiency in Buildings, 1988, American Council for an Energy Efficient Economy, 1988.

Chernick, P., "Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels," in Proceedings of the 1988 Annual Meeting of the American Solar Energy Society, American Solar Energy Society, Inc., 1988, pp. 553-557.

Chernick, P., "Capital Minimization: Salvation or Suicide?," in I.C. Bupp, ed., The New Electric Power Business, Cambridge Energy Research Associates, 1987, pp. 63-72.

Chernick, P., "The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in Current Issues Challenging the Regulatory Process, Center for Public Utilities, Albuquerque, New Mexico, April, 1987, pp. 36-42.

Chernick, P., "Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 547-562.

Bachman, A. and Chernick, P., "Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System," in Proceedings of the Fifth NARUC Biennial Regulatory Information Conference, National Regulatory Research Institute, Columbus, Ohio, September, 1986, pp. 2093-2110.

Eden, P., Fairley, W., Aller, C., Vencill, C., Meyer, M., and Chernick, P., "Forensic Economics and Statistics: An Introduction to the Current State of the Art," The Practical Lawyer, June 1, 1985, pp. 25-36.

Chernick, P., "Power Plant Performance Standards: Some Introductory Principles," Public Utilities Fortnightly, April 18, 1985, pp. 29-33.

Chernick, P., "Opening the Utility Market to Conservation: A Competitive Approach," in Energy Industries in Transition, 1985-2000, Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November, 1984, pp. 1133-1145.

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," in Risk Analysis in the Private Sector, pp. 401-416, Plenum Press, New York, 1985.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

Chernick, P. and Meyer, M., "Capacity/Energy Classifications and Allocations for Generation and Transmission Plant," in Award Papers in Public Utility Economics and Regulation, Institute for Public Utilities, Michigan State University, 1982.

Chernick, P., Fairley, W., Meyer, M., and Scharff, L., Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December, 1981.

Chernick, P., Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September, 1977.

## PRESENTATIONS

Demand-Side Management and the Global Environment Conference; Washington, D.C., April 22, 1991; "Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs."

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28, 1991; "Least Cost Planning and Gas Utilities."

NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24, 1991; "Least-Cost Planning in a Multi-Fuel Context."

Understanding Massachusetts' New Integrated Resource Management Rules; Needham, Massachusetts, November 9, 1990; "Accounting for Externalities: Why, Which and How?"

National Association of Regulatory Utility Commissioners' National Conference on Environmental Externalities; Jackson Hole, Wyoming, October 1, 1990; "Monetizing Externalities in Utility Regulations: The Role of Control Costs."

New England Gas Association Gas Utility Managers' Conference; Woodstock, Vermont, September 10, 1990; "Increasing Market Share Through Energy Efficiency."

Lawrence Berkeley Laboratory Training Program for Regulatory Staff; Berkeley, California, February 2, 1990; "Quantifying and Valuing Environmental Externalities."

District of Columbia Natural Gas Seminar; Washington, D.C., May 23, 1989; "Conservation in the Future of Natural Gas Local Distribution Companies".

Massachusetts Natural Gas Council; Newton, Massachusetts, April 3, 1989; "Conservation and Load Management for Natural Gas Utilities".

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop; Portsmouth, N.H., January 22-23, 1989; "Assessment and Valuation of External Environmental Damages."

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QFs".

Massachusetts Energy Facilities Siting Council; Boston, Massachusetts, May 30, 1985; "Reviewing Utility Supply Plans".

National Association of State Utility Consumer Advocates; Williamstown, Massachusetts, August 13, 1984; "Power Plant Performance".

National Conference of State Legislatures; Boston, Massachusetts, August 6, 1984; "Utility Rate Shock".

National Governors' Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20, 1984; "Review and Modification of Regulatory and Rate Making Policy".

Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27, 1983; "Insurance Market Assessment of Technological Risks".

**REPORTS** (excluding reports incorporated in testimony)

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports," (with E. Caverhill), January 1991.

"Comments on the 1991-1992 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," (with Plunkett, J., et al.), September 1990.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with I. Goodman and E. Espenhorst), Boston Gas Company, December 22, 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with E. Espenhorst), Boston Gas Company, December 22, 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with E. Caverhill), Boston Gas Company, December 22, 1989.

"Conservation Potential in the State of Minnesota," (with I. Goodman) Minnesota Department of Public Service, June 16, 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12, 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June, 1985.

"Final Report: Rate Design Analysis," Pacific Northwest Electric Power and Conservation Planning Council, December 18, 1981.

## ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals; August 1987 to March 1988.

Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations; March 1988 to June 1989.

## EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission); and PUC (Public Utilities Commission).

1. MEFSC 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General; June 12, 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with S.C. Geller.

2. MEFSC 78-17; Northeast Utilities 1978 forecast; Massachusetts Attorney General; September 29, 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. MEFSC 78-33; Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General; November 27, 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with S.C. Geller.

5. MDPU 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1, 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with S.C. Geller.

7. MDPU 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4, 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

8. MDPU 20055; Petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G.& E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General; January 23, 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. MDPU 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2, 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. MDPU 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16, 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. MEFSC 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16, 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. MDPU 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19, 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. Texas PUC 3298; Gulf States Utilities Rate Case; East Texas Legal Services; August 25, 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of cancelled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M.B. Meyer.

14. MEFSC 79-1; Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General; November 5, 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. MDPU 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12, 1980.

    Conservation as an energy source; advantages of per-kwh allocation over per-customer-month allocation.

16. MDPU 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26, 1981 and February 13, 1981.

    Filing requirements, certification, qualifying facility (QF) status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of QFs in specific areas; wheeling; standardization of fees and charges.

17. MEFSC 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12, 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. MDPU 558; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; May, 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. MDPU 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7, 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. DCPSC FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29, 1982.

    Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. NHPUC DE1-312; Public Service of New Hampshire - Supply and Demand; Conservation Law Foundation, *et al.*; October 8, 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. Massachusetts Division of Insurance; Hearing to Fix and Establish 1983 Automobile Insurance Rates; Massachusetts Attorney General; October, 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. Illinois Commerce Commission 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15, 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10, 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. Connecticut Public Utility Control Authority 830301; United Illuminating Rate Case; Connecticut Consumers Counsel; June 17, 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. MDPU 1509; Boston Edison Plant Performance Standards; Massachusetts Attorney General; July 15, 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. Massachusetts Division of Insurance; Hearing to Fix and Establish 1984 Automobile Insurance Rates; Massachusetts Attorney General; October, 1983.

    Profit margin calculations, including methodology, interest rates.

28. Connecticut Public Utility Control Authority 83-07-15; Connecticut Light and Power Rate Case; Alloy Foundry; October 3, 1983.

    Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. MEFSC 83-24; New England Electric System Forecast of Electric Resources and Requirements; Massachusetts Attorney General; November 14, 1983, Rebuttal, February 2, 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. Michigan PSC U-7775; Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; February 21, 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. MDPU 84-25; Western Massachusetts Electric Company Rate Case; Massachusetts Attorney General; April 6, 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. MDPU 84-49 and 84-50; Fitchburg Gas & Electric Financing Case; Massachusetts Attorney General; April 13, 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. Michigan PSC U-7785; Consumers Power Fuel Cost Recovery Plan; Public Interest Research Group in Michigan; April 16, 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. FERC ER81-749-000 and ER82-325-000; Montaup Electric Rate Cases; Massachusetts Attorney General; April 27, 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. Maine PUC 84-113; Seabrook 1 Investigation; Maine Public Advocate; September 13, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. MDPU 84-145; Fitchburg Gas and Electric Rate Case; Massachusetts Attorney General; November 6, 1984.

    Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. Pennsylvania PUC R-842651; Pennsylvania Power and Light Rate Case; Pennsylvania Consumer Advocate; November, 1984.

    Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. NHPUC 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15, 1984.

    Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. Massachusetts Division of Insurance; Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November, 1984.

    Profit margin calculations, including methodology and implementation.

40. MDPU 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12, 1984.

    Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. Maine PUC 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11, 1984.

    Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113; Seabrook 2 Investigation; Maine PUC Staff; December 14, 1989.

    Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. MDPU 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14, 1985.

    Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vermont PSB 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21, 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. MDPU 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25, 1985, and October 18, 1985.

    Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. MDPU 85-121; Investigation of the Reading Municipal Light Department; Wilmington (MA) Chamber of Commerce; November 12, 1985.

    Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in streetlighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Massachusetts Division of Insurance; Hearing to Fix and Establish 1986 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; November, 1985.

    Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. New Mexico Public Service Commission 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23, 1985.

    Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. Pennsylvania PUC R-850152; Philadelphia Electric Rate Case; Utility Users Committee and University of Pennsylvania; January 14, 1986.

    Limerick 1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. MDPU 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19, 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. Pennsylvania PUC 4-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24, 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. New Mexico Public Service Commission 2004; Public Service of New Mexico, Palo Verde Issues; New Mexico Attorney General; May 7, 1986.

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. Illinois Commerce Commission 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13, 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. New Mexico Public Service Commission 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18, 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. City of Boston, Public Improvements Commission; Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18, 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. Massachusetts Division of Insurance; Hearing to Fix and Establish 1987 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cashflows, installment income, income tax status, and return to shareholders.

57. MDPU 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21, 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. New Mexico Public Service Commission 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19, 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. MDPU 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9, 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. Massachusetts Division of Insurance 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. Texas PUC 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17, 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. Minnesota PUC ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17, 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. Massachusetts Division of Insurance 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2, 1987. Rebuttal October 8, 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. MDPU 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4, 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. Massachusetts Division of Insurance 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14, 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. Massachusetts Division of Insurance; 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5, 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. Massachusetts Department of Public Utilities 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2, 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. Massachusetts Department of Public Utilities 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18, 1988, and November 8, 1988.

Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. Massachusetts Department of Public Utilities 88-67; Boston Gas Company; Boston Housing Authority; June 17, 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. Rhode Island Public Utility Commission Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24, 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. Massachusetts Division of Insurance 88-22; 1989 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues August 12, 1988, supplemented August 19, 1988; Losses and Expenses September 16, 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. Vermont Public Service Board Docket No. 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26, 1988.

Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. Vermont House of Representatives, Natural Resources Committee; House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group; February 21, 1989.

Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. MDPU 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6, 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. Vermont Public Service Board Docket No. 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1, 1989.

Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. Boston Housing Authority Court 05099; Gallivan Boulevard Task Force vs. Boston Housing Authority, *et al.;* Boston Housing Authority; June 16, 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. MDPU 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30, 1989.

Prudence of BECo's decision of spend $400 million from 1986-88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. MDPU 88-123; Petition of Riverside Steam and Electric Company; Riverside Steam and Electric; July 24, 1989. Rebuttal, October 3, 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. MDPU 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13, 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. Vermont Public Service Board Docket 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19, 1989. Surrebuttal February [illegible], [illegible]90.

Analysis of a proposed 450-M[illegible], 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency inve[illegible] Vermont, including potential for efficiency savings. Analysis of Vermont elec[illegible] supply. Identification of possible im[illegible]ements [illegible] proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. MDPU 89-239; Inclusion of Externalities in Energy [illegible]pply Planning, Acquisition and Dispatch for Massachusetts Utilities; December, 1989; April, 1990; May, 1990.

Critique of Division of Energy Resources report on ex[illegible]es. Methodology for evaluating external costs. Propos[illegible]es for environmental and economic externalities of fuel supply and use.

82. California Public Utilities Commission; Inco[illegible]ation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21, 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. Illinois Commerce Commission Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25, 1990. Joint rebuttal testimony with David Birr, August 14, 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. Maryland Public Service Commission Case No. 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18, 1990.

    Rationale for demand-side management, and BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. Indiana Utility Regulatory Commission; Integrated Resource Planning Docket; Indiana Office of Utility Consumer Conselor; November 1, 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. MDPU Dockets 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5, 1990.

    Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. MEFSC 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14, 1990.

    Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. Maine PUC Docket No. 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19, 1991.

    Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Commonwealth of Virginia State Corporation Commission Case No. PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6, 1991.

    Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Massachusetts DPU Docket No. 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17, 1991.

    Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Commonwealth of Massachusetts; Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech; May 13, 1991.

    NEPCo rates for power purchses from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. Vermont PSB Docket No. 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19, 1991.

    Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. South Carolina Public Service Commission Docket No. 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13, 1991. Surrebuttal October 2, 1991.

    Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Maryland Public Service Commission Case No. 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19, 1991.

    Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport Planning Board; AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1, 1991.

    New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. Massachusetts DPU Docket No. 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Compoany; October 4, 1991.

    Updates on pollutant externality values. Addition of values for chlorofluorocarbrons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

Exhibit ____PLC-2

**Florida Power Corporation's Planned Polk County Capacity Additions**

| On-Line Date | Added Capacity (MW) | Total Added Capacity (MW) | Capacity Factor | Added Energy (GWh) | Total Added Energy (GWh) | Source |
|---|---|---|---|---|---|---|
| [1] | [2] | [3] | [4] | [5] | [6] | [7] |
| 1998 | 235 | 235 | 55% | 1,132 | 1,132 | Natural gas-fired combined cycle |
| 1999 | 470 | 705 | 55% | 2,264 | 3,397 | Two 235 MW natural gas-fired combined cycle units |
| 2000 | 235 | 940 | 55% | 1,132 | 4,529 | Natural gas-fired combined cycle |

Notes:

[1]: Integrated Resource Study, page 346. Affects winter peak at end of year listed.
[2]: Integrated Resource Study, page 346. Capacity is winter rating.
[3]: Cumulative sum of [2].
[4]: Integrated Resource Study, page 84.
[5]: [2]*8760*[4]
[6]: Cumulative sum of [5].
[7]: Integrated Resource Study, page 346.

Exhibit ____PLC–3



Florida Power Corporation's Integrated Resource Study
Projected Loads and Resources (MW)

| Year [1] | Peak Demand Before C&LM [2] | Load Management [3] | Conservation Resources [4] | Peak Demand After C&LM [5] | With Polk County Units: Supply Side Resources [6] | With Polk County Units: Resource Surplus [7] | With Polk County Units: Reserve Margin [8] | Without Polk County Units: Supply Side Resources [9] | Without Polk County Units: Resource Surplus [10] | Without Polk County Units: Reserve Margin [11] |
|---|---|---|---|---|---|---|---|---|---|---|
| 1991/92 | 7,618 | 822 | 116 | 6,681 | 7,189 | 508 | 8% | 7,189 | 508 | 8% |
| 1992/93 | 8,031 | 976 | 134 | 6,921 | 7,588 | 667 | 10% | 7,588 | 667 | 10% |
| 1993/94 | 8,354 | 1,138 | 169 | 7,047 | 8,379 | 1,332 | 19% | 8,379 | 1,332 | 19% |
| 1994/95 | 8,688 | 1,309 | 208 | 7,172 | 8,413 | 1,241 | 17% | 8,413 | 1,241 | 17% |
| 1995/96 | 8,977 | 1,428 | 248 | 7,300 | 8,558 | 1,258 | 17% | 8,558 | 1,258 | 17% |
| 1996/97 | 9,258 | 1,528 | 309 | 7,422 | 8,558 | 1,136 | 15% | 8,558 | 1,136 | 15% |
| 1997/98 | 9,532 | 1,667 | 329 | 7,536 | 8,708 | 1,172 | 16% | 8,708 | 1,172 | 16% |
| 1998/99 | 9,803 | 1,787 | 369 | 7,647 | 8,943 | 1,296 | 17% | 8,708 | 1,061 | 14% |
| 1999/00 | 10,071 | 1,899 | 410 | 7,762 | 9,164 | 1,402 | 18% | 8,459 | 697 | 9% |
| 2000/01 | 10,332 | 1,932 | 450 | 7,950 | 9,339 | 1,389 | 17% | 8,399 | 449 | 6% |
| 2001/02 | 10,590 | 1,965 | 487 | 8,138 | 9,339 | 1,201 | 15% | 8,399 | 261 | 3% |

Exhibit ____PLC-3
Florida Power Corporation's Integrated Resource Study
Projected Loads and Resources (MW)

Notes:

[1]: C&LM savings are attributed to the earlier possible peak, e.g. 1992 savings reduce 1991/92 peak demand.
[2]: [3]+[4]+[5]
[3]: Integrated Resource Study, page 225. Includes Load Management, Voltage Reduction and Residential Heatworks.
[4]: Integrated Resource Study, page 225–227. Total – Cogen – [3].
[5]: Integrated Resource Study, page 348, column 7, for 1990/91 through 2000/01.
Thereafter, Integrated Resource Study, page 344, column 12.
[6]: Integrated Resource Study, page 348, column 6. Supply resources are only reported through the year 2000/01. Thereafter they are assumed constant.
[7]: [6]–[5]
[8]: [7]/[5]
[9]: [6]–(Polk County Units' capacity)
[10]: [9]–[5]
[11]: [10]/[5]

Exhibit ____PLC–4

## FPC's Projected Pre–C&LM Electricity Requirements and Conservation and Load Management Resources

Page 1 of 5: Residential Sector Electricity Requirements and Conservation

| Year | Growth in Pre–C&LM Electricity Requirements From 1991 | Growth in Conservation From 1991 | | | Growth in Conservation as % of Growth in Electricity Requirements | Conservation as % of Total Electricity Requirements |
|---|---|---|---|---|---|---|
| | Sales (GWh) | Peak Savings (MW) | Energy Savings (GWh) | Load Factor | Sales | Sales |
| [1] | [2] | [3] | [4] | [5] | [6] | [7] |
| 1991 | 12,508 | 53 | 159 | 34% | 1.3% | 1.3% |
| 1992 | 954 | 7 | 11 | 18% | 1.2% | 1.3% |
| 1993 | 1,482 | 22 | 30 | 15% | 2.1% | 1.4% |
| 1994 | 2,058 | 54 | 62 | 13% | 3.0% | 1.5% |
| 1995 | 2,619 | 90 | 98 | 12% | 3.7% | 1.7% |
| 1996 | 3,165 | 127 | 135 | 12% | 4.3% | 1.9% |
| 1997 | 3,674 | 164 | 172 | 12% | 4.7% | 2.0% |
| 1998 | 4,151 | 201 | 209 | 12% | 5.0% | 2.2% |
| 1999 | 4,611 | 238 | 247 | 12% | 5.3% | 2.4% |
| 2000 | 5,048 | 276 | 284 | 12% | 5.6% | 2.5% |
| 2001 | 5,478 | 313 | 321 | 12% | 5.9% | 2.7% |
| 2002 | 5,905 | 347 | 353 | 12% | 6.0% | 2.8% |

Exhibit ____PLC-4
FPC's Projected Pre-C&LM Electricity Requirements and
Conservation and Load Management Resources

Page 2 of 5: Commercial and Industrial Sector Electricity Requirements and Conservation

| Year | Growth in Pre-C&LM Electricity Requirements From 1991 | Growth in Conservation From 1991 | | | Growth in Conservation as % of Growth in Electricity Requirements | Conservation as % of Total Electricity Requirements |
|---|---|---|---|---|---|---|
| | Sales (GWh) | Peak Savings (MW) | Energy Savings (GWh) | Load Factor | Sales | Sales |
| [1] | [2] | [3] | [4] | [5] | [6] | [7] |
| 1991 | 11,096 | 53 | 149 | 32% | 1.3% | 1.3% |
| 1992 | 580 | 3 | 8 | 34% | 1.3% | 1.3% |
| 1993 | 1,110 | 5 | 14 | 30% | 1.3% | 1.3% |
| 1994 | 1,740 | 8 | 23 | 31% | 1.3% | 1.3% |
| 1995 | 2,523 | 12 | 32 | 31% | 1.3% | 1.3% |
| 1996 | 3,039 | 15 | 42 | 32% | 1.4% | 1.4% |
| 1997 | 3,530 | 18 | 51 | 32% | 1.4% | 1.4% |
| 1998 | 4,000 | 21 | 60 | 32% | 1.5% | 1.4% |
| 1999 | 4,457 | 25 | 69 | 32% | 1.5% | 1.4% |
| 2000 | 4,910 | 28 | 79 | 32% | 1.6% | 1.4% |
| 2001 | 5,362 | 31 | 88 | 32% | 1.6% | 1.4% |
| 2002 | 5,811 | 34 | 96 | 32% | 1.6% | 1.4% |

Exhibit ____PLC-4

**FPC's Projected Pre-C&LM Electricity Requirements and Conservation and Load Management Resources**

Page 3 of 5: Total Electricty Requirements and Conservation, Including Street Lighting and Public Authority Sales

| Year | Growth in Pre-C&LM 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 Savings (MW) | Energy Savings (GWh) | Load Factor | Peak | Sales | Peak | Sales |
| [8] | [9] | [10] | [11] | [12] | [13] | [14] | [15] | [16] | [17] | [18] |
| 1991 | 6,636 | 25,443 | 44% | 106 | 370 | 40% | 1.6% | 1.5% | 1.6% | 1.5% |
| 1992 | 983 | 1,601 | 19% | 9 | 19 | 23% | 1.0% | 1.2% | 1.5% | 1.4% |
| 1993 | 1,396 | 2,755 | 23% | 28 | 45 | 18% | 2.0% | 1.6% | 1.7% | 1.5% |
| 1994 | 1,718 | 4,029 | 27% | 63 | 85 | 15% | 3.6% | 2.1% | 2.0% | 1.5% |
| 1995 | 2,053 | 5,439 | 30% | 102 | 130 | 15% | 4.9% | 2.4% | 2.4% | 1.6% |
| 1996 | 2,341 | 6,566 | 32% | 142 | 177 | 14% | 6.1% | 2.7% | 2.8% | 1.7% |
| 1997 | 2,623 | 7,627 | 33% | 182 | 223 | 14% | 7.0% | 2.9% | 3.1% | 1.8% |
| 1998 | 2,897 | 8,631 | 34% | 223 | 269 | 14% | 7.7% | 3.1% | 3.5% | 1.9% |
| 1999 | 3,168 | 9,603 | 35% | 263 | 316 | 14% | 8.3% | 3.3% | 3.8% | 2.0% |
| 2000 | 3,435 | 10,544 | 35% | 304 | 363 | 14% | 8.8% | 3.4% | 4.1% | 2.0% |
| 2001 | 3,697 | 11,473 | 35% | 344 | 408 | 14% | 9.3% | 3.6% | 4.4% | 2.1% |
| 2002 | 3,954 | 12,398 | 36% | 381 | 449 | 13% | 9.6% | 3.6% | 4.6% | 2.2% |

Exhibit ___PLC-4
FPC's Projected Pre-C&LM Electricity Requirements and
Conservation and Load Management Resources

Page 4 of 5: Total Conservation and Load Management

| Year | Growth in Conservation and Load Management From 1991 | | | Growth in C&LM as % of Growth in Electricity Requirements | | C&LM as Percent of Total Electricity Requirements | |
|---|---|---|---|---|---|---|---|
| | Peak Savings (MW) | Energy Savings (GWh) | Load Factor | Peak | Sales | Peak | Sales |
| [19] | [20] | [21] | [22] | [23] | [24] | [25] | [26] |
| 1991 | 802 | 408 | 6% | 12.1% | 1.6% | 12.1% | 1.6% |
| 1992 | 136 | 24 | 2% | 13.8% | 1.5% | 12.3% | 1.6% |
| 1993 | 309 | 56 | 2% | 22.1% | 2.0% | 13.8% | 1.6% |
| 1994 | 505 | 102 | 2% | 29.4% | 2.5% | 15.6% | 1.7% |
| 1995 | 715 | 153 | 2% | 34.8% | 2.8% | 17.5% | 1.8% |
| 1996 | 875 | 207 | 3% | 37.4% | 3.1% | 18.7% | 1.9% |
| 1997 | 1,035 | 259 | 3% | 39.5% | 3.4% | 19.8% | 2.0% |
| 1998 | 1,195 | 311 | 3% | 41.2% | 3.6% | 20.9% | 2.1% |
| 1999 | 1,355 | 364 | 3% | 42.8% | 3.8% | 22.0% | 2.2% |
| 2000 | 1,507 | 415 | 3% | 43.9% | 3.9% | 22.9% | 2.3% |
| 2001 | 1,581 | 462 | 3% | 42.8% | 4.0% | 23.1% | 2.4% |
| 2002 | 1,650 | 505 | 3% | 41.7% | 4.1% | 23.2% | 2.4% |

Exhibit ___PLC-4
FPC's Projected Pre-C&LM Electricity Requirements and
Conservation and Load Management Resources



Notes:

[1]: 1991 peak demand is assumed to occur in the winter of 1990/91, and so on.
[2]: Integrated Resource Study, page 352, plus the conservation resources of [4].
[3]: Integrated Resource Study, pages 225-7. Residential excludes Residential Heatworks
[4]: Integrated Resource Study, pages 221-3. Residential excludes Residential Heatworks
[5]: ([4]*1000)/[3]/8766
[6]: [4]/[2]
[7]: ([4] in 1991 + [4])/([2] in 1991 + [2])
[8]: [1]
[9]: Integrated Resource Study, page 348 col. 7, and page 334, col 12; plus conservation in [13].
[10]: Integrated Resource Study, page 352, column 13, plus conservation in [13].
[11]: ([10]*1000)/[9]/8766
[12]: Sum of Residential and C&I data in [5]. (There was no additional MW saving for street lighting or public authorities.)
[13]: Sum of residential and C&I data in [6], and street lighting conservation (IRS, p. 223). (There was no additional public authority conservation.)
[14]: ([13]*1000)/[12]/8766
[15]: [12]/[9]
[16]: [13]/[10]
[17]: ([12] in 1991 + [12])/([9] in 1991 + [9])
[18]: ([13] in 1991 + [13])/([10] in 1991 + [10])
[19]: [1]
[20]: [12]+(Load management, Voltage Reduction and Residential Heatworks). From IRS, pages 225-7.
[21]: [13]+(Load management, Voltage Reduction and Residential Heatworks). From IRS, pages 221-3.
[22]: ([21]*1000)/[20]/8766
[23]: [20]/[9]
[24]: [21]/[10]
[25]: ([20] in 1991 + [20])/([9] in 1991 + [9])
[26]: ([21] in 1991 + [21])/([10] in 1991 + [10])

## Exhibit ___ PLC-5
## Utility Expenditures on DSM, as Percent of Revenues

| | 1991 expenditure (1991$) | [1] as % of '91 revenues | Total program expenditure (1991$) | # yrs covered | Avg annual expenditure | [5] as % of '91 revenues |
|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [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-6
## 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 peak |
|---|---|---|---|---|---|---|
| | [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-7 (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% |
| Wisconsin Electric (growth 1991-2000 inclusive) | | | | | | |
| Res.: | 77 | NA | | 67 | NA | |
| C/I: | 211 | NA | | 183 | NA | |
| Total: | 288 | 5,140 | 5.6% | 250 | 786 | 31.8% |

# Exhibit ___ PLC-7 (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% |

## Notes to Exhibit ___ PLC–7, 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-8
## Cost of Residential and C/I DSM Savings

| | Budget (1991$) | Incrmtl MW svgs | Adjusted for 15% reserve | Incrmtl GWH svgs | DSM capacity factor | Amortized budget | gross $/kWh |
|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] |
| BECO ( DSM in 1990-1994) | | | | | | | |
| Res | $31,714,800 | 7 | 8 | 66 | 107.63% | $3,055,476 | $0.0463 |
| C/I | $190,685,040 | 109 | 125 | 454 | 47.55% | $18,371,033 | $0.0405 |
| Total | $222,399,840 | 116 | 133 | 520 | 51.17% | $21,426,509 | $0.0412 |
| Com/Electric (DSM in 1991-1995) | | | | | | | |
| Res | $14,552,000 | NA | NA | 62 | NA | $1,401,973 | $0.0226 |
| C/I | $116,910,000 | NA | NA | 688 | NA | $11,263,377 | $0.0164 |
| Total | $131,462,000 | NA | NA | 750 | NA | $12,665,350 | $0.0169 |
| EUA (DSM in 1991-1995) | | | | | | | |
| Res | $18,451,000 | 7 | 8 | 37 | 60.63% | $1,777,612 | $0.0478 |
| C/I | $58,194,080 | 73 | 84 | 198 | 31.12% | $5,606,551 | $0.0283 |
| Total | $76,645,080 | 80 | 92 | 236 | 33.70% | $7,384,162 | $0.0313 |
| NEES (DSM in 1991) | | | | | | | |
| Total | $85,000,000 | 46 | 53 | 141 | 34.99% | $8,189,094 | $0.0581 |
| New York State Electric and Gas (DSM in 1991-2008) | | | | | | | |
| Total | $1,550,063,000 | 788 | 906 | 2,779 | 40.26% | $149,336,615 | $0.0537 |

Assumptions:

| | | |
|---|---|---|
| Life of DSM savings | 15 | years |
| Real discount rate | 5% | |
| reserve margin | 15% | |

Notes:

[1],[2],[4]: see Exhibit PLC-8 for source, except for NEES, whose 1991 figures are from "Demand -Side Management at New England Electric: Implementation, Evaluation and Incentives," Alan Destribates et al., NARUC Santa Fe 1991 Conference Proceedings.

All utilities' expenditures and savings are cumulative over the life of the program.

[3]: [2]*1.15. 15% reserve margin assumed.

[4]: Note that line losses are not included; this results in overstating of the final cost of DSM ([10]).

[5]: [4]*1000/[2]*8760

[6]: [1], amortized over 15 years, at a 5% real discount rate (nominal discount rate is 10%).

[7]: [6]/[4]*10^6

# Exhibit ___ PLC-9 (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
avg : Average
blank cell: Utility does not have such a program
+d : + Design assistance
+f : + Financing

IC: Incremental Costs
(NC): Covered under new construction program
n yr pb: n Year Payback Buydown (n=# of yrs)
TBD: To be determined
TC: Total Costs

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# Notes to Exhibit ___ PLC-9, 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-9 (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 |

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# Notes to Exhibit ___ PLC-9, 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-9:

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-10: 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-10: 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-10: 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-10: 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–11, (part 1): Participation Rate for FPC's Residential DSM Programs

| Year | Home Inspection Audit [1] | Home Energy Checkup [2] | Home Energy Fixup [3] | Load Management [4] | Load Management Thermal Storage [5] | Res. Loan Program [6] | Res. Blower Door Program [7] | Res. Insulation Program [8] | Res. HVAC Allowance Program [9] | Res. Tuneup Program [10] | Res. Trade Ally Program [11] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1982 | 3.8% | 1.0% | 2.2% | 2.0% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1983 | 8.2% | 1.5% | 5.6% | 6.7% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1984 | 13.0% | 1.7% | 8.6% | 9.4% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1985 | 17.9% | 1.8% | 10.4% | 12.8% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1986 | 22.5% | 1.8% | 11.9% | 17.1% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1987 | 25.3% | 1.7% | 12.6% | 20.7% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1988 | 27.8% | 1.7% | 13.2% | 24.1% | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1989 | 30.2% | 1.6% | 14.0% | 27.4% | 0.1% | N/A | N/A | N/A | N/A | N/A | N/A |
| 1990 | 32.2% | 1.6% | 14.5% | 31.3% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% | 0.1% |
| 1991 | 34.1% | 1.6% | 15.0% | 35.0% | 3.9% | 0.1% | 0.1% | 0.2% | 0.3% | 0.1% | 0.1% |
| 1992 | 35.9% | 1.6% | 15.5% | 38.4% | 7.8% | 0.2% | 0.2% | 0.4% | 0.5% | 0.2% | 0.2% |
| 1993 | 37.5% | 1.6% | 16.0% | 41.7% | 11.7% | 0.3% | 0.3% | 0.5% | 0.9% | 0.3% | 0.3% |
| 1994 | 39.1% | 1.6% | 16.3% | 44.7% | 15.6% | 0.4% | 0.4% | 0.6% | 1.2% | 0.4% | 0.4% |
| 1995 | 40.7% | 1.6% | 16.8% | 46.8% | 19.5% | 0.5% | 0.5% | 0.7% | 1.5% | 0.5% | 0.5% |
| 1996 | 42.2% | 1.6% | 17.2% | 48.8% | 23.4% | 0.5% | 0.5% | 0.8% | 1.8% | 0.5% | 0.5% |
| 1997 | 43.7% | 1.6% | 17.6% | 50.0% | 27.3% | 0.6% | 0.6% | 0.9% | 2.1% | 0.6% | 0.6% |
| 1998 | 45.1% | 1.6% | 18.0% | 51.2% | 31.2% | 0.7% | 0.7% | 1.0% | 2.4% | 0.7% | 0.7% |
| 1999 | 46.6% | 1.6% | 18.5% | 52.4% | 35.0% | 0.7% | 0.7% | 1.1% | 2.6% | 0.7% | 0.7% |

Source: Florida Power Corporation, "Energy Efficiency and Conservation Programs," Feb. 12th, 1991.

## Exhibit ___ PLC-11 (part 2): Participation Rate for FPC's C/I DSM Programs

| Year | Business Inspection Audit [1] | Business Energy Analysis [2] | C/I Blower Door [3] | Indoor Lighting Incentive [4] | C/I HVAC Tuneup [5] | C/I Fixup [6] | C/I HVAC Allowance [7] | C/I Motor Efficiency [8] | Demand Reduction Capital Offset [9] | C/I Heat Pipe Development [10] |
|---|---|---|---|---|---|---|---|---|---|---|
| 1982 | 0.3% | 0.4% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1983 | 3.0% | 0.8% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1984 | 5.9% | 1.4% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1985 | 9.2% | 1.9% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1986 | 11.4% | 2.0% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1987 | 13.1% | 2.0% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1988 | 15.4% | 2.1% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1989 | 19.3% | 2.2% | N/A | N/A | N/A | N/A | N/A | N/A | N/A | N/A |
| 1990 | 23.0% | 2.3% | 0.0% | 0.1% | 0.1% | 0.0% | 0.1% | 0.2% | 0.00% | 0.00% |
| 1991 | 26.3% | 2.4% | 0.1% | 0.3% | 0.3% | 0.1% | 0.3% | 0.5% | 0.01% | 0.01% |
| 1992 | 29.4% | 2.5% | 0.2% | 0.5% | 0.5% | 0.2% | 0.6% | 0.8% | 0.01% | 0.03% |
| 1993 | 32.3% | 2.5% | 0.3% | 0.7% | 0.7% | 0.3% | 1.0% | 1.1% | 0.02% | 0.04% |
| 1994 | 34.9% | 2.6% | 0.3% | 0.9% | 0.9% | 0.3% | 1.6% | 1.3% | 0.03% | 0.06% |
| 1995 | 37.4% | 2.6% | 0.4% | 1.1% | 1.1% | 0.4% | 2.2% | 1.6% | 0.03% | 0.07% |
| 1996 | 39.8% | 2.7% | 0.4% | 1.3% | 1.3% | 0.5% | 2.9% | 1.8% | 0.04% | 0.08% |
| 1997 | 42.2% | 2.8% | 0.5% | 1.4% | 1.4% | 0.5% | 3.5% | 2.0% | 0.05% | 0.09% |
| 1998 | 44.5% | 2.8% | 0.6% | 1.6% | 1.6% | 0.6% | 4.0% | 2.3% | 0.05% | 0.10% |
| 1999 | 46.7% | 2.9% | 0.6% | 1.8% | 1.8% | 0.6% | 4.6% | 2.5% | 0.06% | 0.11% |

Source: Florida Power Corporation, "Energy Efficiency and Conservation Programs," Feb. 12th, 1991.

Exhibit ____PLC-12

**Florida Power's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs**

Page 1 of 4: Total Demand-Side Resources, By Sector

| | Residential Sector | | | | Commercial & Industrial Sector | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Percent of New Sales Met With New DSM | Incremental Annual New DSM GWh | Cumulative New DSM GWh | Cumulative New DSM MW | Percent of New Sales Met With New DSM | Incremental Annual New DSM GWh | Cumulative New DSM GWh | Cumulative New DSM MW |
| [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
| 1992 | 15% | 143 | 302 | 86 | 10% | 58 | 207 | 79 |
| 1993 | 20% | 106 | 408 | 116 | 20% | 106 | 313 | 119 |
| 1994 | 25% | 144 | 552 | 157 | 25% | 157 | 471 | 179 |
| 1995 | 25% | 140 | 692 | 197 | 30% | 235 | 706 | 268 |
| 1996 | 25% | 137 | 828 | 236 | 30% | 155 | 860 | 327 |
| 1997 | 25% | 127 | 956 | 273 | 30% | 147 | 1,007 | 383 |
| 1998 | 25% | 119 | 1,075 | 307 | 30% | 141 | 1,149 | 437 |
| 1999 | 25% | 115 | 1,190 | 339 | 30% | 137 | 1,286 | 489 |
| 2000 | 25% | 109 | 1,299 | 370 | 30% | 136 | 1,422 | 541 |
| 2001 | 25% | 108 | 1,407 | 401 | 30% | 135 | 1,557 | 592 |
| 2002 | 25% | 107 | 1,513 | 432 | 30% | 135 | 1,692 | 643 |

Exhibit ____PLC-12

**Florida Power's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs**

Page 2 of 4: Total Demand-Side Resources, All Sectors

| Year | Cumulative New Energy Savings | Cumulative New Peak Savings | Energy Savings as Percent of Sales | Peak Savings as Percent of Peak Load | Cumulative Energy Savings as Percent of Cum. Sales Growth | Cumulative Peak Savings as Percent of Cum. Peak Growth |
|---|---|---|---|---|---|---|
| | GWh | MW | | | | |
| | [10] | [11] | [12] | [13] | [14] | [15] |
| 1992 | 572 | 165 | 2.1% | 2.2% | 16.5% | 6.0% |
| 1993 | 783 | 235 | 2.8% | 2.9% | 17.3% | 9.3% |
| 1994 | 1,085 | 336 | 3.7% | 4.0% | 19.3% | 13.4% |
| 1995 | 1,460 | 466 | 4.7% | 5.4% | 21.2% | 17.5% |
| 1996 | 1,751 | 563 | 5.5% | 6.3% | 22.0% | 19.5% |
| 1997 | 2,026 | 656 | 6.1% | 7.1% | 22.5% | 21.0% |
| 1998 | 2,286 | 743 | 6.7% | 7.8% | 22.9% | 22.0% |
| 1999 | 2,538 | 828 | 7.2% | 8.4% | 23.2% | 22.8% |
| 2000 | 2,783 | 911 | 7.7% | 9.0% | 23.5% | 23.4% |
| 2001 | 3,026 | 993 | 8.2% | 9.6% | 23.7% | 24.0% |
| 2002 | 3,268 | 1,075 | 8.6% | 10.2% | 23.9% | 24.5% |

**Exhibit ____PLC–12**

**Florida Power's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs**

Page 3 of 4: Additional Demand Side Resources

| | Residential | | Commercial/Industrial | | Total | |
|---|---|---|---|---|---|---|
| Year | Energy Savings | Peak Reduction | Energy Savings | Peak Reduction | Energy Savings | Peak Reduction |
| [16] | [17] | [18] | [19] | [20] | [21] | [22] |
| 1992 | 132 | 26 | 50 | 23 | 182 | 49 |
| 1993 | 218 | 40 | 150 | 61 | 368 | 101 |
| 1994 | 331 | 50 | 299 | 118 | 629 | 168 |
| 1995 | 435 | 54 | 524 | 204 | 960 | 258 |
| 1996 | 534 | 56 | 669 | 259 | 1,203 | 315 |
| 1997 | 624 | 55 | 808 | 312 | 1,432 | 367 |
| 1998 | 707 | 52 | 940 | 363 | 1,646 | 414 |
| 1999 | 784 | 47 | 1,068 | 411 | 1,852 | 459 |
| 2000 | 856 | 42 | 1,193 | 460 | 2,050 | 501 |
| 2001 | 927 | 35 | 1,320 | 508 | 2,247 | 543 |
| 2002 | 1,001 | 32 | 1,447 | 556 | 2,448 | 588 |

Exhibit ____PLC-12

**Florida Power's Demand Side Resources Based on Plans of Utilities with Collaboratively Designed Programs**



Notes:

[1]: 1992 corresponds to 1991/92, and so on.

[2]: Figure in 1994 and thereafter based on the expected energy savings in the residential sector achieved in collaboratively designed programs, with an adjustment for FPC's high 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 gross residential sales growth
gross sales = net sales (IRS, p. 352 col. 2) + conservation (not LM; IRS, pp 221-2)

[4]: FPC's 1991 consevation, plus cumulative sum of [3]. See IRS, pp.221-2.

[5]: [4]/8766*1000/(40% load factor).

[6]: Figure in 1995 and thereafter based on the expected energy savings in the commercial and industrial sector achieved in collaboratively designed programs, with an adjustment for FPC's high growth rate. (Collaborative data can be found in Exhibit ___PLC-6). The figures in the earlier years represent a judgement-based ramp-up period. The ramp-up period in the C&I sector is expected to be longer than in the residential sector due to longer new construction lead times.

[7]: [6]*gross annual C&I sales growth
gross sales = net sales (IRS, p. 352 col. 5) + conservation (not LM; IRS, pp 222-3)

[8]: FPC's 1991 consevation, plus cumulative sum of [7]. See IRS, pp. 222-3.

[9]: [4]/8766*1000/(30% load factor)

[10]: [4]+[8]+street lighting savings. See IRS, page 223.

[11]: [5]+[9]+street lighting savings. There are no street lighting peak savings.

[12]: [10]/(total sales not for resale plus all C&LM savings excluding cogeneration savings)
See IRS, page 352 column 12 for sales; pages 221-3 for C&LM.

[13]: [11]/(total pre-C&LM peak demand, excluding cogeneration savings)
See IRS, page 334, column 12 for net demand; pages 225-7 for conservation.

[14]: ([10]-1991 C&I, Res, and street light savings)/(cumulative growth from 1991 in total sales). See [12] for sources.

[15]: ([11] - 1991 C&I and Res. savings)/(cumulative growth from 1991 in peak demand). See [13] for sources.

[16]: [1]

[17]: [4]-(projected residential (except heatworks) savings). See IRS, pages 221-3.

[18]: [5]-(projected residential (except heatworks) savings). See IRS, pages 225-7.

[19]: [8]-(projected C&I savings). See IRS, pages 221-3.

[20]: [9]-(projected C&I savings). See IRS, pages 225-7.

[21]: [17]+[19]

[22]: [18]+[20]

Exhibit ___PLC-13

# Comparison of Florida Power Corporation's Resource Plan With a Resource Plan Utilizing Collaborative-Scale Conservation

Florida Power Corporation's Current Resource Plan (in Megawatts)

| Year [1] | Peak Demand Before C&LM [2] | Load Management [3] | FPC Planned Conservation Resources [4] | Peak Demand After C&LM [5] | Supply Resources W/o Polk [6] | Polk County Units [7] | Total Supply Reources [8] | Reserve Margin [9] |
|---|---|---|---|---|---|---|---|---|
| 1991/92 | 7,618 | 822 | 116 | 6,681 | 7,189 | 0 | 7,189 | 7.6% |
| 1992/93 | 8,031 | 976 | 134 | 6,921 | 7,588 | 0 | 7,588 | 9.6% |
| 1993/94 | 8,354 | 1,138 | 169 | 7,047 | 8,379 | 0 | 8,379 | 18.9% |
| 1994/95 | 8,688 | 1,309 | 208 | 7,172 | 8,413 | 0 | 8,413 | 17.3% |
| 1995/96 | 8,977 | 1,428 | 248 | 7,300 | 8,558 | 0 | 8,558 | 17.2% |
| 1996/97 | 9,258 | 1,548 | 289 | 7,422 | 8,558 | 0 | 8,558 | 15.3% |
| 1997/98 | 9,532 | 1,667 | 329 | 7,536 | 8,708 | 0 | 8,708 | 15.6% |
| 1998/99 | 9,803 | 1,787 | 369 | 7,647 | 8,708 | 235 | 8,943 | 16.9% |
| 1999/00 | 10,071 | 1,899 | 410 | 7,762 | 8,459 | 705 | 9,164 | 18.1% |
| 2000/01 | 10,332 | 1,932 | 450 | 7,950 | 8,399 | 940 | 9,339 | 17.5% |
| 2001/02 | 10,590 | 1,965 | 487 | 8,138 | 8,399 | 940 | 9,339 | 14.8% |

Collaborative-Scale Conservation Resource Plan (in Megawatts)

| 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 [15] | Revised Polk County [16] | Total Supply Reources [17] | Reserve Margin [18] |
|---|---|---|---|---|---|---|---|---|
| 1991/92 | 7,618 | 657 | 165 | 6,796 | 7,189 | 0 | 7,189 | 5.8% |
| 1992/93 | 8,031 | 781 | 235 | 7,015 | 7,588 | 0 | 7,588 | 8.2% |
| 1993/94 | 8,354 | 910 | 336 | 7,107 | 8,379 | 0 | 8,379 | 17.9% |
| 1994/95 | 8,688 | 1,047 | 466 | 7,176 | 8,413 | 0 | 8,413 | 17.2% |
| 1995/96 | 8,977 | 1,143 | 563 | 7,271 | 8,558 | 0 | 8,558 | 17.7% |
| 1996/97 | 9,258 | 1,238 | 656 | 7,365 | 8,558 | 0 | 8,558 | 16.2% |
| 1997/98 | 9,532 | 1,334 | 743 | 7,455 | 8,708 | 0 | 8,708 | 16.8% |
| 1998/99 | 9,803 | 1,430 | 828 | 7,546 | 8,708 | 0 | 8,708 | 15.4% |
| 1999/00 | 10,071 | 1,519 | 911 | 7,641 | 8,459 | 470 | 8,929 | 16.9% |
| 2000/01 | 10,332 | 1,546 | 993 | 7,793 | 8,399 | 705 | 9,104 | 16.8% |
| 2001/02 | 10,590 | 1,572 | 1,075 | 7,943 | 8,399 | 705 | 9,104 | 14.6% |

Exhibit ___PLC–13
Comparison of Florida Power Corporation's Resource Plan With a Resource Plan Utilizing Collaborative–Scale Conservation

Notes:

[1]: For conservation and load management resources, 1991/92 corresponds to 1992 in other tables, and so on.
[2]: [3]+[4]+[5]
[3]: Integrated Resource Study, pages 225–6. Includes Load Management, Voltage Reduction and Residential Heatworks.
[4]: Integrated Resource Study, page 225–227. Total – Cogen – [3].
[5]: Integrated Resource Study, page 344, column 12.
[6]: Integrated Resource Study, page 348, column 6, minus [7]. 2001/02 supply resources are assumed to remain at 2000/01 levels here.
[7]: Integrated Resource Study, pages 346, 348.
[8]: [6]+[7]
[9: ([8]–[5])/[5]
[10]: [1]
[11]: [2]
[12]: [3]*0.8 Peak savings from isolated load management programs are assumed to be cut by 20% due to interaction with comprehensive conservation programs.
[13]: The conservation reaources available to FPC through a collaborative scale conservation program are derived in Exhibit ___PLC–12.
[14]: [11]–[12]–[13]
[15]: [6]
[16]: The rescheduling of new supply is described in the text.