Ex. 64

(Errata are incorporated!)

DOCKET NO. 930548-EG
DOCKET NO. 930549-EG
DOCKET NO. 930550-EG
DOCKET NO. 930551-EG

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

LEGAL ENVIRONMENTAL ASSISTANCE FOUNDATION, INC.

TESTIMONY OF PAUL CHERNICK

APRIL 29, 1994

Resource Insight, Inc.

Suite 1000 • 18 Tremont Street • Boston, MA 02108

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I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 18 Tremont Street, Suite 1000, Boston, Massachusetts.

Q: Summarize your professional education and experience.

A: I received a SB degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a SM 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, and since August 1990 in my current position at Resource Insight. In those capacities, I have advised a variety of clients on utility matters, including, 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___(LEAF-PC-1).

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over one hundred times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Minnesota Public Utilities Commission, the South Carolina Public Service Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

Q: Have you testified previously before this Commission?

A: Yes. I testified before the Commission in two dockets related to Florida utilities' obligations to pursue integrated resource planning and failures to establish need for proposed facilities: Docket Nos. 910759 and 910833-EI on behalf of Floridians for Responsible Utility Growth.

Q: Have you been involved in least-cost utility resource planning?

A: Yes. I have been involved in utility planning issues since 1978, including load forecasting, the economic evaluation of proposed and existing power plants, and the establishment of rates for qualifying facilities. Most recently, I have been a consultant to various energy conservation design collaboratives in New England, New York, and Maryland; to CLF's conservation design project in Jamaica; to CLF interventions in a number of New England rule-making and adjudicatory proceedings; to the Boston Gas Company on avoided costs and conservation program design; to the City of Chicago and Cincinnati on their utilities' resource plans; to the Maryland People's Counsel, Iowa Consumer Advocate, and South Carolina Consumer Advocate on a variety of least-cost planning issues; to environmental groups in North Carolina, Ohio, and Michigan on DSM planning; and to several parties on incorporating externalities in utility planning and resource acquisition. I also assisted the DC PSC in drafting order 8974 in Formal Case 834 Phase II, which established least-cost planning requirements for the electric and gas utilities serving the District.

I am one of the principle authors of the five-volume report *From Here to Efficiency,* a comprehensive review of DSM planning, ratemaking, and implementation issues published by the Pennsylvania Energy Office.

Q: Have you testified previously on rate design issues?

A: Yes. Much of my early work for the Massachusetts Attorney General concerned retail rate design, including determination of marginal costs.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Legal Environmental Assistance Foundation, Inc. (LEAF).

Q: What is the purpose of your direct testimony?

A: The purpose of my direct testimony is to address the conservation goals for Florida Power and Light (FPL), Florida Power Corporation (FPC), Tampa Electric Company (TECo), and Gulf Power Company (Gulf). I refer to these companies collectively as "the utilities."

Q: Please outline your testimony.

A: In addition to my qualifications and this introduction, my testimony is composed of three major substantive sections. Section III discusses certain generic requirements that utility Integrated Resource Planning (IRP) processes must meet if they are to be consistent with the public interest and the welfare of the utility's ratepayers. Section IV considers in some detail the problems and errors in FPL's goal-setting process. Section V proposes goals for all four utilities, consistent with the IRP principles in Section III and the available data.

My testimony, as it relates to FPC's goals, is limited to the issues that LEAF and FPC have agreed to dispute in this docket: the choice of the screening test to be used in constructing the goals portfolio, and the goals that should result from that choice. All other issues between LEAF and FPC are the subject of a stipulation filed in this docket. Nothing should be construed to conflict with that stipulation.

Q: Are you sponsoring any exhibits?

A: Yes. Six Exhibits are attached to my testimony.

III. Elements Of A Reasonable IRP Process

Q: What elements must be included in an integrated-resource-planning (IRP) process, in order for the process to be reasonable?

A: A partial list, focusing on the items of greatest concern in these dockets, would include the following:

- A forecast of demand for energy services
- Screening of supply options

- Development of a least-cost base-case supply plan, usually without additional DSM
- Development of avoided costs
- Characterization of DSM measures
- Screening of DSM measures
- Design and screening of DSM programs to deliver cost-effective measures
- Determination of participation rates in cost-effective programs
- Integration of supply and demand, including the following steps:
    - determine least-cost supply plan with all cost-effective DSM
    - check that all DSM remains cost-effective with the full DSM portfolio
    - review rate and bill effects of the planned portfolio
- Determination of final plan
- Identification of short-term action plan

The order of these steps is not always critical to the process, nor need all the steps be conducted simultaneously.

I use the term "option" to refer to any decisions in the IRP process, including whether to include a technological measure, whether to offer a program, and whether to enhance or expand a measure or program.

Q: Why is the reasonableness of the planning process important in setting numerical DSM goals?

A: Rule 25-17.0021(3), FAC, requires each utility to propose goals and provide 10-year projections of demand and energy savings based upon the utility's "most recent planning process." Since the goals are tied to the planning process, reasonable proposals for goals require a reasonable planning process.

A. The DSM Screening Process

Q: What is the purpose of screening DSM options?

A: Screening identifies the DSM options that are cost-effective compared to the utility's supply alternatives. The options that pass screening are likely to be part of the optimal least-cost plan.

Q: What aspects of the screening process for DSM are particularly important for these proceedings?

A: While all the utilities have properly implemented some parts of the screening process, all of them have improperly treated some aspects of screening. For example:

- While all four utilities compute both the Rate Impact Measure (RIM) Test and the Total Resource (TRC) Cost Test, all of them rely primarily on the RIM measure in constructing their goals.[1]
- The utilities do not properly distinguish between measures and programs.
- Some of the utilities improperly apply joint program overhead costs in the evaluations of measures that might be included in those programs.

The remainder of this section considers each of these issues in turn.

[1]Florida Power and Light also uses a quick-and-dirty version of the RIM in determining the incentives to be offered, even in estimating the potential effects of a portfolio supposedly intended to maximize the TRC.

1. The Primary Screening Test

Q: What is the appropriate test of the cost-effectiveness of utility DSM options?

A: Utilities are publicly regulated entities with fundamental obligations to maximize benefits to their customers and to the wider community that constitutes the public interest. The purpose of utility DSM programs, like many other utility activities (supply acquisition, the design of distribution systems, rate design), is to maximize the net value of the energy services that the utility normally provides, or (almost equivalently) to minimize the costs of providing service. Hence, the basic test of cost-effectiveness is a measure of total costs.

Q: What costs and benefits should be included in the total-cost test?

A: At the very least, the test should include all effects on ratepayers as consumers of electric energy services, whether those effects flow through electric bills or are borne directly by the ratepayers. Even if the definition of the public interest were restricted to the utility's ratepayers, the cost test should include *all* effects on ratepayers, whether through electric bills, direct energy-equipment expenditures, bills for other utilities (e.g., water, natural gas), environmental compliance, or other means. While the terminology used varies between jurisdictions, this might be called the *All-Ratepayers Test.*

Limiting the scope of the test to the utility's ratepayers is not generally justified. The PSC's responsibilities extend to all the citizens of Florida, without regard to which utility serves them. Increasing costs to consumers outside the utility's service territory does not usually serve the public interest. Hence, most jurisdictions have replaced the All-Ratepayers Test with the Total Resource Cost Test, which attempts to capture all the costs and benefits of the DSM program, regardless of who bears them.[2] Again, the terminology varies, but adding externalities (costs and benefits falling outside the energy services system, such as air pollution and employment) to the TRC produces a more comprehensive test, frequently referred to as the *Societal Test.* For the purposes of this testimony, I will refer to the TRC, generally without explicitly specifying whether the test includes externalities.[3]

Total resource costs include outlays by the utility and customers 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 passes the Total Resource Cost Test if its benefits exceed its costs. A cost-effective measure will reduce utility revenue requirements and the total costs of providing electric service.[4]

Q: As you have defined it, is the TRC the only important test in DSM screening?

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[2]Consideration of direct costs is often restricted to the particular state, or to an integrated utility system.

[3]The cost-benefit test for utility resource decisions should include externalities. However, all the opinions expressed herein (other than the support of eternality valuation) would remain unchanged by the omission of externalities.

[4]In Docket 920606, FPL asserted (through the testimony of Dr. Sim and others) that measures passing the TRC could increase revenue requirements and average bills. My testimony in that docket demonstrated that Dr. Sim's "proof" of this absurd assertion depended on inconsistent assumptions about the number of participants: Dr. Sim assumed high participation to create significant rate increases, and assumed low participation to create high average bills and revenue requirements. Any consistent set of participation assumptions would produce reduced bills (Tr. 292-301).

A: Yes. The purpose of utility resource planning is to minimize cost and maximize net benefits. The TRC is the appropriate test for determining whether the benefits of a DSM investment equal or exceed the costs.

While they are not relevant for screening, other economic analyses are appropriate at other stages of the integrated resource planning process. DSM program design must consider the attractiveness of the design to potential participants. Some form of participant test will therefore be important in determining the level of incentives and design of programs. Since customers do not usually make their decisions on the basis of net present value, the traditional participant test is of little value. The programs for each market segment should be designed to pass the tests that energy consumers and decision makers (such as facility managers, HVAC contractors, plumbers, retailers, and other trade allies) actually apply, such as years to payback or to positive cash flow. Potential participants in some segments may actually care more about non-financial aspects of program design, such as simplicity of participation and reduction of participant risk.

The analysis of program design from the perspective of potential participants must also consider the differences in the market barriers faced by various types of customers, including industrial, large commercial, small commercial, government and institutional, elderly, low-income, and other residential customers, and in different market segments (new construction, emergency appliance replacement, retrofit).

After an initial DSM portfolio is constructed, the effects of the DSM and supply options on rates and bills should be determined, on an annual basis, for each customer class. I discuss this rate and bill analysis further in Section III.E.

Q: What role should the Ratepayer Impact Measure Test have in determining the cost-effectiveness of a demand-side option?

A: It should have no role in the economic screening of demand-side programs or the technologies incorporated in such programs. Screening with the RIM will lead to the rejection of economical DSM.[5]

Q: How does use of the RIM test lead utilities to reject cost-effective DSM?

A: Demand-side management is cost-effective if its total benefits exceed its total costs under the Total Resource Cost Test. The present-value RIM test is not a measure of total costs,[6] nor a useful measure of equity or rate impact. The RIM test varies from the TRC primarily in its treatment of the participant. Rather than including the participant's costs and benefits, along with those of all other customers, the RIM treats the participant as an alien party, of no concern to the utility or the Commission. The RIM ignores

- the costs the participant may incur in participating in the program,
- the benefit to the participant from any rebate or other incentives,
- the benefit to the participant of reduced bills.

The treatment of the latter two items is particularly inconsistent, since the RIM includes both the incentives and lost revenues as costs.

Revenue shifts involve a loss to one group of customers, but a gain to another. The RIM effectively adds the losses to the costs of DSM (subtracts them from its benefits), but does not account for the gain. If this same principle were applied to rate design, no rate would ever be decreased,

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[5]In addition, setting incentives based on the RIM test, as Florida's utilities advocate, will result in unnecessarily low participation, excessive administrative costs per installation, and the loss of cost-effective DSM.

[6]This is another point about which FPL was confused in Docket 920606.

because a rate change creates benefits for some customers but net costs to others.[7]

Q: Do utilities apply the equivalent of the RIM test to decisions other than DSM?

A: No. As I explain above, rate design and cost allocation would be impossible if utilities refused to increase bills to some customers. Neither rate design nor cost allocation is generally reviewed with the RIM test.[8]

The RIM test, for example, would indicate that utilities could reduce rates by requiring customers to purchase their own services and meters, and for larger customers, transformers and secondary lines. This change in policy would pass the RIM test, but probably increase total energy service costs; utilities recognize that such a change would be counter-productive, since customers care about energy service costs, not rates.

Utilities routinely raise rates and bills to some customers, to reduce total revenue requirements. If utilities worried about rate impacts in supply planning, they would:

- Avoid baseload plants because of short-term effects. When a utility brings a major new supply (especially a baseload plant) into service, it typically increases bills and rates in the short term, to reduce them in the

[7]Unlike DSM, rate design and cost allocation shift costs between customers without directly reducing total costs.

[8]Applying the RIM test to rate design would result in incentives to increase usage (such as declining block rates, requiring master-metering, providing rebates for wasteful energy usage) so long as marginal costs were less than average rates (including customer charges), even if marginal costs were greater than marginal rates.

long term.[9] This reduction in total costs comes at a considerable price for the elderly, economically marginal businesses, and other customers who may not remain on the system long enough to experience the long-term benefits.

- Favor NUGs. The capital costs of utility-owned plants are recovered in a front-loaded pattern, increasing the short-term rate effects compared to levelized cost recovery by non-utility generators (NUGs). Utilities do not usually reflect the benefits of reduced rate effects in evaluating NUGs versus utility plants in resource planning.
- Avoid baseload plants for equity reasons. Baseload plants, whose benefits are largely reductions in energy rates but whose costs are allocated largely on the basis of peak demand, tend to increase rates and bills to low-load-factor rate classes and, within the demand-metered classes, low-load-factor customers, while decreasing costs for high-load-factor classes and customers.

Rate impacts and equity considerations are not usually considered in selecting supply resources; where these factors are considered at all, they are secondary concerns, and do not dominate resource selection.

Q: Does primary reliance on the TRC for screening DSM options mean that the ratepayer impacts should be ignored?

A: Not at all. The ratepayer effects of the DSM portfolio should be examined to flag any equity problems or excessive rate impacts. The RIM test, however, is

[9] Florida Power and Light admits as much in the testimony of Dr. Sim, but minimizes the extent of the rate effects by considering only a single relatively inexpensive combined-cycle unit, rather than the series of coal plants FPL projects adding as early as 2000 (depending on the DSM scenario and the FPL source document).

not a very meaningful test of equity or rate changes. It looks at rate effects on a measure-by-measure or program-by-program basis, and estimates only the average effect on non-participants of a particular utility DSM program or measure. Individual measures and programs cannot meaningfully be considered equitable or inequitable in isolation.

A measure that fails the RIM can increase the equity of the portfolio. For example, a residential lighting program may be the only program in which many residential customers can participate for several years, until their major appliances are ready for replacement.[10] Excluding a cost-effective lighting program would prevent these customers from participating in DSM, and make the portfolio less equitable.[11]

Equity effects should be evaluated for the portfolio as a whole, but the standard present-value RIM test is not useful for this purpose. It does not assess the equity effects of DSM among and within classes and it does not properly determine the pattern of rates and bills over time.

2. *Measures and Programs*

Q: Do the utilities properly screen DSM options?

A: No. DSM options should be screened in at least two steps:

1. *Measure screening* compares the costs and benefits of each technological option, or measure, to determine whether the measure should be added to any program in which it might logically fit. This screening step indicates which measures should be undertaken, if the

[10]Most utilities find that residential lighting programs pass the TRC.

[11]This is particularly true if the costs of the DSM program are allocated to all customer classes, rather than just the participating classes.

opportunity arises. Measure screening can also compare the net benefits of alternatives, to determine which measures should be emphasized. Measures should often be screened in several variants, representing different usage levels, ambient conditions (whether the water heater in indoors or out), interactions (whether the home is electrically heated, and if so, whether by resistance or heat pump), efficiency levels of related equipment, and so on. This screening should include only the costs of the measure itself (equipment, installation, any incremental costs of analysis or administration for each installation) assuming that a program exists to deliver the measure. Incentive levels, program delivery mechanisms, and the level of free riders are generally not relevant in measure screening.

2. *Program screening* compares the costs and benefits of each program, as it would be delivered. A program consists of a set of measures and a delivery mechanism: for example, a comprehensive residential retrofit program might include

- a blower-door-driven audit, combined with installation of hot-water conservation measures (water heater wrap, showerhead) and compact fluorescent lamps;
- correction of major bypasses and duct sealing, if indicated by the audit;
- recommendation of major retrofits (insulation, fuel switching, heat pump installation, window treatments, tree planting); and
- direct delivery of major retrofits selected by the customer.

The benefits of the program are the sum of the benefits of the measures that would be installed due to the program, reflecting the mix of measures to be installed, as well as rates of free riders and free drivers. The costs of the program are the costs of the measures (net of the costs free riders would have incurred anyway), plus the joint costs of the program: marketing, intake, administration, and delivery (e.g., getting the team performing the initial audit and installation to the house).

Q: Why is it important to distinguish between these screening steps?

A: In general, it is important to remember that measures are not programs, that one measure may be delivered through many programs, and one program may include many measures. The most important effect of proper screening is to separate the direct cost of measures from the overhead costs of programs. Measures should only be included in programs if the *added* benefits of the measures exceed the *added* costs; a program should only be implemented if its *total* benefits exceed its *total* costs.[12]

Q: Have the utilities properly screened both measures and programs?

A: No. The utilities have screened only measures.[13] Cost-effective measures can usually be combined into cost-effective programs, since at least a few of the measures in the program will generate enough benefits to cover the program costs.

Q: Do the Commission's orders in this proceeding excuse the utilities from properly screening programs?

[12]This formulation prohibits the bundling of non-cost-effective measures with cost-effective measures to create programs that pass the TRC as a whole.

[13]FPL refers to variants on measures (primarily to reflect differences in rate class) as "programs". This misuse of a term widely accepted in the demand-planning field indicates a lack of familiarity with DSM program design.

A: No. The Fourth Procedural Order (p. 9) requires that the utilities "evaluate the appropriate combination of measures for purposes of proposing numeric goals." The "appropriate combination of measures" for cost-effectiveness screening must reflect the costs and benefits of realistic programs, including a realistic mix of measures and the associated overhead.

3. Treatment of Program Costs

Q: Is it appropriate to reflect program costs at the measure-screening level?

A: No. Measure screening should ignore all costs shared with other measures in a DSM program, such as costs of marketing, administration, setting up visits, traveling to the site, and auditing the building. Only the direct incremental costs of the measure should be included in this analysis: materials, direct labor, and any other costs of installing the measure that is being evaluated.

Q: Why should program costs not be allocated out to measures?

A: The individual measures do not cause the program costs, and deleting a measure will not reduce the joint program costs. Any assignment of those program costs to measures is inherently arbitrary; until the program is fully designed and structured, there will be no way of even knowing whether the assignment of costs actually equals the expected cost of the program.

Allocating program costs to measures can make cost-effective measures look uneconomic. For example, consider a potential program consisting of two measures, each of which is cost-effective, having the following costs and benefits:

Measure	Benefits	Costs	Net Benefit	Installations	Total Net Benefits
Measure 1	$500	$200	$300	10,000	$3,000,000
Measure 2	$50	$20	$30	100,000	$3,000,000
Program	0	$40	($40)	100,000	($4,000,000)

TOTAL	$2,000,000

The program would reduce total cost by $2 million. Since the joint cost of program delivery exceed the net benefits of either measure, the program is only cost-effective if it includes both measures. If Measure 2 were screened before the program was designed,[14] it might be assigned all of the program delivery costs, resulting in an apparent net loss of $10 per installation.[15] This cost-effective measure would then be dropped from further consideration. Measure 1 could not support the overhead for this program by itself, and might also be erroneously viewed as uneconomical, depending on whether the program costs are estimated as $4 million in total or $40 per participant. Hence, $2 million in net benefits might be lost due to the inclusion of program costs in measure screening.

Q: If program costs are not taken into account in measure screening, how can the utility ensure that DSM goals are reasonable and economic?

A: Utilities should base goals on realistically designed programs, not just on measure screening. Utilities should consider utility program costs in *program* screening, not at the measure-screening level. As I noted above, cost-effective measures can usually be combined into cost-effective programs, since at least a few of the measures in the program will generate enough benefits to cover the program costs. However, some high-overhead program designs may turn out not to be cost-effective, especially compared to other program designs for delivering the same measures.

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[14]Since the utilities do not appear to have yet designed programs for delivering measures not in their existing portfolios, they cannot know how the overhead costs might be allocated.

[15]Other approaches, such as allocating costs per installation, could have the same effect. It is not clear how any meaningful allocation could be made prior to program design.

B. Determining Avoided Costs for DSM

Q: How should the utilities estimate the supply costs avoided by DSM?

A: The utilities should reflect the avoidable costs of

- generating capacity, both that related to demand and that related to energy, and including purchases, capital recovery and O&M costs;
- transmission capacity, including capital recovery and O&M costs;
- distribution capacity, including capital recovery and O&M costs;
- fuel and other variable generation energy costs;
- compliance with environmental regulations;
- line losses in the transmission and distribution system;
- quantifiable externalities.

1. Generating Capacity

Q: How should utilities estimate the generating-capacity costs avoidable by DSM?

A: The utility should estimate the cost savings of altering the least-cost supply plan without the DSM to the least-cost supply plan with the DSM. The load shape of the DSM should be realistically modeled, and the amount of DSM should be comparable to the capacity of avoidable supply.[16]

Some of the utilities have treated only combustion turbines (CTs) as avoidable by DSM for screening purposes, even though other, more expensive plants are planned, are avoidable, and are avoided in the utility's integration run.

[16]This can be achieved by modeling the effects of large blocks of DSM, or by treating small increments of supply as avoidable by each DSM option. The utilities generally use the second approach, but do not allow DSM to avoid all supply resources.

2. *Variable Generation Energy Costs*

Q: How should the utilities estimate the variable generation energy costs avoided by DSM?

A: They should compare (1) the dispatch costs (fuel, variable fuel handling, variable O&M) of the base case to (2) the dispatch costs of the same case, minus the energy load avoided by DSM (and without the avoided supply capacity), at an appropriate DSM load shape.

The difference between (1) and (2) is the avoided variable energy costs. The generation energy costs (the dispatch costs, plus capitalized energy) at each load level can then be multiplied by losses at that load level and weighted by the load level, to derive a weighted loss factor.

a) Opportunities for Off-System Sales

Q: Please explain how off-system sales are a benefit of DSM.

A: For utilities with large off-system sales, energy conserved by DSM will often reduce the usage of the marginal unit that would otherwise run to serve off-system sales, rather than the lower-cost unit that would have been marginal if only native loads were served. The avoided energy cost in this situation is greater than that indicated by the native-load dispatch. In addition, DSM can free up energy, capacity, or both for additional off-system sales. If the utility can make additional off-system sales at a profit (above variable costs), it will decrease retail revenue requirements. The benefits of DSM should reflect additional profits (that is, the difference between sale price and avoided cost) due to DSM, as well as the higher avoided energy cost due to off-system sales.

Off-system sales are most important when the utility has an excess of capacity to sell, or an excess of baseload capacity and is able to sell energy released by DSM power for a price higher than the marginal cost of producing the energy.

3. Transmission and Distribution Capacity

Q: How should the utilities estimate avoidable transmission and distribution capacity for DSM?

A: In general, it is not possible to directly compute the difference in T&D investment for the base and DSM cases, due to the lack of system planning models comparable to the system models used in generation planning. Hence, it is usually necessary to estimate T&D costs from historical (and perhaps projected) relationships between investments and the loads served by that investment, and between O&M and loads.

Q: Should avoided T&D costs include only the costs avoided by the utility?

A: No. Regardless of where the customer's usage is metered—at transmission level or after secondary distribution—someone must provide distribution to the end use, which is almost always at secondary voltage. Hence, avoidable T&D should be computed to the secondary level for all customer classes.

4. Line Losses

Q: What line losses should be included in DSM avoided costs?

A: Marginal losses should be included for energy costs, recognizing the variation in marginal losses with load level. Losses rise as load rises (an hence as costs rise), and the incremental losses on an additional kWh of sales in any hour is roughly twice the average value of variable losses in that hour.

Marginal energy losses should reflect the product of the various loss levels and energy costs, which vary over the course of the day and the year, rather than losses at the average load level. Demand-related costs should include average losses at the peak load.

Like distribution costs, losses should be included to the end-use level, which is almost always secondary.

5. *Environmental Compliance Costs*

Q: How should the utilities include the costs of environmental compliance?

A: First, for effects that will be *mitigated*, the utilities should include reasonable estimates of the cost of mitigation. The incremental costs of all emissions-control and effluent-reduction equipment and measures, including all capital and operating costs, the costs of additional fuel consumed due to an increase in plant heat rate, and all other incremental costs should be included in the costs of the resource. The costs in this category cover current costs of existing rules, future costs of existing rules, and future costs of expected rules.

Second, for residual effects that will be *internalized* through taxes, fees, emissions caps or another method, the utilities should include a forecast of those costs, just as it considers future fuel prices in its cost analysis. Examples include the sulfur-allowance provisions of the CAAA, and other rules that can be anticipated today, such as restrictions on emissions of CO_2, mercury, and other air toxics. The costs in this category are simply projections of future internalized costs, and should be treated in the same manner as fuel price or other forecasts. Where future costs are uncertain, avoided costs should include reasonable projections of the expected value.

DSM helps reduce the risk associated with uncertain future environmental compliance costs.

6. Externalities

Q: Should externalities such as environmental and employment impacts be considered in the evaluation of the cost-effectiveness of DSM?

A: Yes.

Q: Do the Commission's current rules address externalities?

A: Yes. Rule 27-17.008 (3), Florida Administrative Code incorporates by reference the "Manual on the Cost-Effectiveness of Demand-Side Management Programs and Self-Service Wheeling Proposals". The rule (p. 5) provides: "This test (the TRC) may be turned into a Societal Test by excluding tax credit benefits, by including costs and benefits of externalities, and by using a societal discount rate, assuming that the costs and benefits of externalities are quantifiable."

Q: How should externalities be incorporated into utility planning?

A: The residual environmental and other external effects of power plant construction and operation (the effects that remain after mitigation efforts and that will not be internalized) should be monetized, and estimates of the social cost should be included in resource planning and acquisition. The utilities' existing system and their planned additions (especially the coal plants planned by FPL) contribute to regional and global environmental concerns in a way that DSM or other clean resources would not.

Q: Can the costs and benefits be reasonably quantified?

A: Yes. For example, the Goodman Group has prepared a Florida-specific analysis that evaluates the employment impacts of DSM measures considered in the SRC Report.[17] Many other jurisdictions have quantified and monetized externalities from air emissions and other effects, as summarized in Exhibit ____ (LEAF-PC-2). The Commission could reasonably select values that fall within the ranges shown in Exhibit___(LEAF-PC-2). These values are more reasonable estimates than the zero values for all pollutants currently used by the utilities.

Q: Do any of the utilities credit DSM with reducing environmental costs and other external costs in these dockets?

A: No.

7. Risk Mitigation

Q: How should the effects of risk be incorporated in DSM valuation?

A: DSM improves a utility's ability to manage supply risk. This results in lower expected costs, and lower volatility and long-run uncertainty in costs. Base-case avoided supply costs should thus be increased to reflect both (1) the difference between base-case avoided costs and the higher statistically expected avoided costs of expanding supply under uncertainty and (2) the value of reduced volatility and uncertainty.

Q: Which attributes of efficiency resources improve a utility's ability to manage risk?

A: Studies by the Northwest Power Planning Council, Oak Ridge National Laboratory, and others have found that, more than any other resource, efficiency can help utilities adapt to an uncertain future through: (1)

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[17]Krier, Betty, Ian Goodman, and Peter Kelly-Detwiler. 1993. "Employment Impacts of Electricity Efficiency in Florida." Tallahassee: Florida Energy Office.

flexibility; (2) short lead time; (3) availability in small increments; and (4) tendency to grow with load.

Q: In what ways do efficiency resources exhibit these characteristics?

A: Demand-side resources are flexible because once a utility has developed the capability to acquire them, it can change its acquisition plans quickly and inexpensively as needs change.

If a utility maintains the capability to deliver full-scale efficiency programs, it can measure the time between resource expenditure and resource service in days or weeks rather than in years. Because efficiency investments produce electricity savings almost immediately, a utility need not invest in resources far in advance of need, as is the case with many supply options. Together, the short lead times and small increments associated with efficiency resources allow a utility to match more closely resource acquisition with resource need.

Q: How do efficiency resources coincide with variations in load?

A: The potential for DSM affecting new construction and equipment expansion varies directly with service-area load growth. Thus, a utility committed to capturing these resources automatically synchronizes its new resource acquisitions with swings in resource needs.[18]

In addition, the savings produced by previous efficiency investments also tend to track load. For example, increasing industrial output in existing facilities will raise electricity use. If those facilities use high-efficiency motors, the increase in electricity use will be less than with standard motors.

[18]New construction and equipment expansion are also "lost opportunity" resources, that can only be captured as they become available.

Similar expectations should also hold for commercial and residential customers; for example, thermal efficiency improvements in building construction will reduce the effect of weather on load.

Compared to supply, efficiency resources therefore reduce the uncertainty surrounding the rate and magnitude of future load growth, thereby reducing the costs of maintaining resource options against future contingencies and the costs of over-and under-building.

Q: Have any utilities and regulators quantified the risk-mitigating advantages of energy-efficiency resources?

A: The Northwest Power Planning Council (NPPC, pp. 2:930–931) considered the "added advantages" of energy efficiency, including "the ability to track local growth" and the tendency of "savings [to] increase as the weather becomes more severe."[19] Based on the risk analyses and other studies,[20] NPPC increased the avoided costs for energy-efficiency programs by 10% to account for these planning benefits. Ontario Hydro includes a 10% preference for DSM, to reflect fuel-price risks. The Vermont Public Service Board requires the electric utilities under its jurisdiction to include a 10% risk preference for DSM. This risk-reduction adder is a part of avoided costs for screening DSM.

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[19]Northwest Power Planning Council. 1991. *1991 Northwest Conservation and Electric Power Plan.* Portland, Or.: NPPC.

[20]NPPC also recognizes the environmental benefits of energy efficiency.

C. Estimating the Market for DSM

Q: How should the utilities estimate the achievable market potential of cost-effective DSM options?

A: The participation in a DSM program, and the acceptance, adoption or penetration of individual measures within the program, depend on the nature of the measures and the design of the program. In general, programs that address the right decision-maker,[21] offer rapid payback, small (or no) cash outlays, rapid transition to positive cash flow, limited risk, and minimal administrative burdens have the highest acceptance. The most successful program designs vary with the capabilities and constraints of customers in each market segment. In some situations, multiple programs should be offered to meet the needs of different groups within a customer class, such as offering large commercial customers a simple rebate program for prescribed measures (for customers unwilling to undertake complex analyses, or in a hurry to renovate space) and an open-ended customer-rebate program for complex packages of system and building improvements (for customers who have unusual opportunities, strong design and decision-making capabilities, and the time to exploit them).

The projection of achievable participation can be based on the experience of other utilities with appropriately designed and implemented programs.

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[21]For example, homeowners usually select their own replacement refrigerators, but air conditioners are recommended or selected by HVAC contractors, and water heaters by plumbers; builders select most appliances in new construction; landlords select most appliances, even if tenants pay the utility bill.

D. Integrating Supply and Demand

Q: What is the function of integration in IRP?

A: Integration combines the resource options — utility and non-utility, supply side and demand management — and determines the best mix of resources.

Q: How should resource options be integrated?

A: The central objective of IRP is minimizing the net present value of total costs, so this should be the principal objective of integration, subject to other concerns, such as constraints on reliability and rate effects.

Integration must also recognize the difference between DSM retrofit resources, which can be deferred until they are most cost-effective, and market-driven lost-opportunity resources, which can only be captured when they become available. Lost opportunities occur during new construction, expansion, industrial process change, equipment replacement, and efficiency upgrades (since a mediocre efficiency improvement may preclude higher-efficiency installations). Lost-opportunity DSM should be captured whenever cost-effective, since it cannot be deferred, is usually less expensive than later retrofits, and reduces risk, as I explain above in Section III.B.7.

Q: Can the utilities pursue first the measures that pass both the RIM and the TRC test, and then pursue other TRC-passing measures?

A: No. This approach would permanently sacrifice lost opportunities, during the period that only RIM-passing measures are installed. In addition, many of the RIM-only installations would *create* lost opportunities, by installing low-savings, cheap measures that preclude (or greatly increase the costs of) subsequent higher-savings installations.

E. Evaluating and Mitigating Rate Impacts

Q: How should the utilities determine the potential rate impacts of a cost-minimizing DSM portfolio?

A: The utility should determine the revenue requirements for each year in the resource plan and compare it with the revenue requirements for the supply-only plan.[22] Dividing the annual cost by sales produces annual average rates for each plan. Both revenue requirements and rates can be estimated by rate class, if the incidence of costs by class is of immediate interest.[23]

Q: Is this approach preferable to the present-value RIM test?

A: Yes. The timing of rate effects is important. The California Standard Practice Manual (SPM, pp. 18–19), the source of the RIM test used by the Commission and the utilities, notes:

> The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW,...or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW,...or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle impact...and the net present value. Secondary test results are the lifecycle revenue impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio....
>
> The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This shows the cumulative rate change or bill change in a year....

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[22]DSM-related rate effects are usually of greatest concern in the relatively short term. In later years, avoided costs rise and savings accumulate, reducing both rates and bills.

[23]Alternatively, the utility may conclude that average system rate effects are reasonable, and leave to rate cases or other cost-recovery proceedings the determination of inter-class allocations of cost sand benefits.

> If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle [RIM] per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results.[24]

Thus, a full rate-impact analysis must consider annual effects, as well as long-run present values, in terms of both rates and revenue requirements.

The SPM (p. 20) also notes that any long-term projection of RIM effects is problematic:

> Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

Q: Are there any issues that require particular care in the determination of annual rate effects?

A: Yes. It is important not to simply add up the program costs and avoided costs from the screening analyses, for three reasons. First, avoided costs are usually estimated on the deferral basis, which states avoided capacity costs as the change in the present value of costs due to a year's delay in construction. Avoided costs computed in this way will start low and rise with inflation. Revenue requirements and rate effects will actually be determined by the Commission's ratemaking procedures, which allow recovery of a return (and associated income taxes) on the unamortized investment. Ratemaking costs start at a high level, and decline over time, as the initial investment is depreciated. Thus, avoided costs will usually understate DSM's effect on reducing revenue requirements in the early years, when rate effects are most

[24]California Public Utilities Commission and California Energy Commission. 1987. "Standard Practice Manual: Economic Analysis of Demand-Side Management Programs." Sacramento: CPUC and CEC.

likely to be troublesome. Hence, it is essential that rate and bill analyses be based on ratemaking costs, not the avoided costs of deferral.

Second, avoided costs are estimated for a set of units projected to be avoidable at the beginning of the analysis. These projections often reflect an assumption that DSM will avoid mostly peaking units. The actual units avoided by the DSM plan will often differ from those assumed in the avoided-cost computation, and will often be more capital-intensive than the supply resources assumed for avoided-cost determination. The actual avoided supply may be more expensive than the avoided costs; but even if the costs are comparable over 20 or 30 years, avoiding capital-intensive plants will reduce costs the most in the crucial early years.

Third, screening is usually conducted for fairly arbitrary timing of installations, but rate effects will vary with the actual pattern of measure installations. The estimates of rate effects should reflect the lead time required to design, implement, and ramp-up full-scale programs; DSM implementation should not be assumed to proceed faster than is feasible, or even faster than is cost-effective.

Q: How should the utility determine whether rate or bill effects are excessive?

A: There is no simple answer to this question. Acceptable levels of rate increases due to DSM depend on the starting level of rates, base-case rate increases without DSM, the distribution of DSM offerings (what percentage of customers can participate), the distribution of DSM savings (such as the percentage of customers with declining bills), provisions to aid vulnerable customers (low-income, at-risk businesses), the average level of customer bills, and the number of jobs created locally through DSM investments.

Q: If DSM results in rates higher than they might be otherwise, does this imply that the rates are excessive or unfair, or that they endanger the state or regional economy?

A: No. The economic attractiveness of the state for business, and the disposable income of households, depends on bills, not rates. As long as DSM is cost-effective, it will decrease the costs of energy services, and bolster the local economy.[25] Whether a difference in rates between the base case and an aggressive DSM plan is a matter for concern depends on how much average bills are reduced, how widely the benefits of DSM are distributed, how rates would otherwise be moving, and how much risk is reduced, as well as the magnitude of the rate difference.

Q: What options could the utilities propose to minimize any identified rate impacts and bill inequities?

A: Several mechanisms are available for minimizing rate or bill problems, such as the following:

- One of the best solutions is to expand the portfolio of DSM programs so that all customers have an opportunity to reduce their electricity usage.
- Removing market barriers, minimizing cash requirements, and targeting marketing efforts will increase the ability of vulnerable customers (low income residentials, marginally viable commercial and industrial firms) to participate and reduce their bills.[26]

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[25]This general relationship is in addition to the positive direct employment effects of DSM.

[26]In Docket 920606, FPL asserted that low-income and elderly customers would never be able to participate in DSM programs, due to cash constraints. This belief betrays a lack of understanding of DSM program design.

- Near-term rate effects can be reduced by amortizing of DSM costs over the measures' lives (as is done for supply), instead of fully expensing the costs each year.
- Problems with excessive rate or bill effects on particular classes can be ameliorated by changing the allocation of DSM costs across classes.
- For some market segments, careful program design can overcome market barriers while still allowing participants to pay a substantial portion of measure costs, either at the time of installation or through energy-service charges.
- If rate effects are excessive in early years, with low avoided costs, the timing of retrofit programs can be stretched to coincide with higher avoided costs due to more expensive fuel and/or the planned construction of baseload plants.

The last two options should be undertaken only with great caution, since sloppy exercise of these options may reduce DSM savings and increase the cost of energy services.

Q: If the portfolio as a whole fails the RIM test, should the DSM plan be rejected?

A: No. The fact that the portfolio fails the RIM test does not imply that rate effects are distributed unfairly, or that rate increases are too large compared to bill reductions. Equity problems should be addressed by changing cost-recovery patterns, altering the allocation of expenditures among and within rate classes, increasing the penetration of programs to groups that would otherwise face higher bills, and changing the timing of particular programs. A DSM plan should not be rejected because it fails the RIM test.

IV. FPL's Goal-Setting Process

Q: What aspects of FPL's goal-setting process will you be discussing?

A: The following sections discuss FPL's screening process, cost-effectiveness analysis methodology, avoided cost, achievable potential, resource integration and goal-setting.

Q: Are there any generic issues that relate to all these various topics?

A: Yes. FPL has not been forthcoming in documentation of its goal-setting process. FPL's filings in this docket have frequently been unenlightening or mutually contradictory, responses to many discovery requests have been unresponsive, and FPL has greatly complicated the review of even the most routine of documents. In many cases, I do not know, and the Commission can not tell, what FPL actually did or why. The testimony I present here is my best understanding of FPL's analysis, given the limited documentation FPL has provided.

These problems in documentation are particularly troublesome in light of FPL's behavior in the Cypress certificate proceeding and the rulemaking that created this docket. During those proceedings, FPL asserted that measures that pass the TRC increase revenue requirements, that the RIM test measured total social costs, that measures that failed the RIM test would increase total customer bills, and that DSM programs cannot be designed to include low-income customers. In the pending docket, FPL has claimed that the use of the deferral method would reduce the cost-effective DSM potential, compared to its poorly matched revenue-requirements approach. All of these assertions have proven to be untrue. In short, the Commission would be ill-advised to rely on FPL's undocumented opinions and assertions of fact, given the historical willingness of FPL staff (including at least one of FPL's witnesses in this case, Mr. Sim) to make assertions that are superficially implausible and fundamentally incorrect.

Q: Please summarize your present understanding of FPL's DSM goal-setting process.

A: FPL first screened measures and determined achievable potential for 2003 based on a four-step process. The measures selected in this screening process were forwarded to a DSM packaging and resource integration analysis. FPL set its DSM goals based on the outcome of the integration analysis, limiting its planned DSM efforts to options that passed the RIM test.

A. *FPL's Screening Process*

1. Introduction

Q: Summarize the four-step process used by FPL to develop its estimates of achievable potential in 2003.

A: As described in Hugues Document 5, FPL first performed a preliminary measure screening (STEP I).[27] For measures that passed the preliminary screening, FPL classified and mapped the measures as competing or complementary (STEP II) and estimated achievable potential for each measure, taking into account the effect of competing measures on adoption probability and the interactive effects of complementary measures on kW and kWh savings per participant (STEP III). FPL then performed a second

[27]This step of the analysis has been variously referred to by FPL as the "first screening" (Hugues testimony, Document No. 9), the "preliminary screening" (Hugues testimony, p. 28), and as the initial screening performed by the marketing department using the DSM design tool (Deposition of Sim, p. 31).

screening (STEP IV), presented in Appendix K (Deposition 4/13/94 and 4/14/94, pp. 54-56).[28] The utility-plan (UP) measures that passed this second screening were considered in the subsequent DSM packaging and resource integration analysis.

Q: Did FPL consider Code-Utility (CUE) and natural-gas measures in this four-step measure screening?

A: Yes. FPL analyzed the cost-effectiveness of natural-gas measures and CUE measures and evaluated the achievable potential of CUE measures (but not natural-gas measures). However, neither the-natural gas measures nor the CUE measures were passed on to integration.

Q: Please describe the first screening.

A: In the first screen (Step 1), FPL screened measures under the TRC and RIM tests, determined the maximum incentive levels it considered appropriate under each of the two tests, and calculated simple participant paybacks with and without incentives.

Q: What was the outcome of the first screening of measures?

A: FPL developed two sets of what FPL terms "measures/programs"[29] to be considered in further analysis: the "RIM scenario" and the "TRC scenario."

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[28]Judging from the Company's statements in deposition, Appendix K may or may not be equivalent to the second screening. For example, according to Dr. Sim, some measures may have been rejected in the "system planning screening" before the "final system planning analysis that appears in Appendix K" (Deposition, 4/13/94 and 4/14/94, p. 56). What the Company calls the "second screening" may include both the system planning screening and the final system planning analysis, whatever they are.

[29]FPL's term "measures/programs" refers to single measures distinguished by rate class, incentive level and existing versus new construction.

From the set of RIM measures, FPL excluded not just measures that failed the RIM test, but also measures that had paybacks of less than two years, and measures that had paybacks (with RIM-level incentives) of greater than the life of the measure. From the set of TRC measures, FPL also excluded measures with paybacks of less than two years, as well as measures that failed the TRC test.

In addition to selecting candidates for further analysis, the first screening determined incentive levels for each measure that were assumed in the second screening, in the determination of achievable potential, and ultimately in the final DSM packaging, resource integration, and goal-setting.[30]

Q: How did FPL set these incentive levels?

A: For the RIM "measure/programs," FPL set the incentive at the lower of (1) the level that produced a RIM test ratio of 1.0 and (2) the level that produced a two-year payback (CEGRR, p. 20). For the TRC "measure/programs," FPL set incentives to produce a two-year payback.

Q: How does the second screening differ from the first?

A: There are at least two major differences between the first and second screenings.[31] First, the analysis period of the initial screening extends at most

[30]According to Mr. Hugues, incentive levels set in first screening may not always have been maintained throughout the goal-setting process. However, FPL has failed to specify such changes in incentive levels and to explain the basis for the revisions.

[31]There may be other differences. Dr. Sim described the first screening as a "quick and dirty method," "virtually identical to" but "not quite as accurate as" the Commission's method. According to Dr. Sim, the only difference in methodology between the first and second screening is some difference in "the total system fuel impact calculation." (4/13/94 and 4/14/94 Deposition of Steven Sim, pp. 17, 47–50)

through the life of the measure. The second screening uses a longer analysis period, in all cases from 1994 through 2016, with each measure initially installed in the middle of 1995. Consequently, a major difference between the first and second screening is the reinstallation of equipment at the end of the life of measure, for all measures with lifetimes less than 21.5 years. Therefore, unlike the initial screening, the second screening includes equipment costs and administrative costs associated with reinstallation (CEGRR, pp. 34–35).

Second, the kW and kWh savings differ from those assumed in first screening. According to the testimony of Hugues (p. 29), the second screening incorporates "achievable potential" savings per participant, while the first screening assumed technical potential savings per participant. To confirm Hugues testimony on this point, I compared the kWh savings per participant from measure RSC-5A in Appendix K (Book 2, p. 312) with the savings assumed in the first screening (Hugues, Document 7 and 8) and the weighted average achievable savings derived in Hugues Document 11:

First screening	560 kWh
Achievable potential	546 kWh
Appendix K	546 kWh

Q: Are there deficiencies in the documentation of the four-step screening process which prevent review of FPL's projection of achievable potential in 2003?

A: Yes. For example:

- Even though many more than half of the measures were rejected in the first screening (according to Hugues Exhibit No. 9), FPL fails to document this analysis. FPL provides only a summary documentation of the analysis for only three measures (Hugues Documents 7 and 8). For these three measures, the Hugues exhibits provide only the total present value costs and benefits and the calculation of incentive levels. They do not provide such crucial information as the annual avoided costs and benefits from which the total present value figures are derived, the measure installation date and the length of the analysis period.

Apparently FPL felt that the first screening was too inaccurate to document (Deposition 4/13/94 and 4/14/94, pp. 47-48), yet accurate enough to be the basis for elimination of a substantial number of options and for the setting of incentive levels. If FPL is reluctant to document the first screening, perhaps it should be ~~too~~ reluctant to rely so heavily on this analysis in its goal-setting.

- Many measures rejected in first screening are passed onto the second screen, even though FPL says these measures were excluded from any further analysis.
- For many of the options that passed the first screen but failed the second screen (according to Hugues testimony, Exhibit No. Document 9), FPL does not document the cost-effectiveness analysis in Appendix K or anywhere else in its filing.
- FPL has not documented its projections in STEP II of achievable potential in 2003 by measure. In response to a request for this documentation, FPL merely referred to the technical potential adjustment factors already provided in Exhibit No. Document 4 of the Hugues testimony (IR LEAF 2-42).[32]

[32]The notation "IR LEAF" refers to an reply to LEAF's interrogatories.

Mr. Hugues describes a straightforward linear screening process, but in reality, the measure selection was a more complicated, less orderly process. For example, measures were bounced back and forth between the Marketing and System Planning departments (Deposition, 4/13/94 and 4/14/94, p. 30), measures rejected in the first screening were mistakenly forwarded to the Planning Department for analysis (Deposition, 4/21/94, p. 76), and measures were rejected by System Planning in a "system planning screening" before the "final system planning screening" presented in Appendix K (Deposition, 4/13/94 and 4/14/94, p. 56).

Q: What conclusion do you draw from FPL's inability to explain and document its analysis?

A: FPL has the responsibility to explain and document its analysis so that the Commission can review whether the analysis is a reasonable basis for setting goals. The Commission cannot rely on FPL's analysis when there is no way to review it fully.

Q: What problems have you identified in the FPL's methodology that would result in underestimating the 2003 total achievable potential?

A: I have identified the following basic problems:

- For some measures, FPL inappropriately substitutes a screening analysis of an existing FPL program for an analysis of individual measures.
- FPL inappropriately rejects measures that have a simple payback of less than two years.
- FPL's measure screening methodology and avoided costs understate the cost-effectiveness of DSM.
- FPL's method for estimating achievable potential for each measure that passes screening is flawed.

Each of these problems in FPL's analysis will result in the under-estimate of achievable potential.

2. *Failure to Screen Required Measures*

Q: What required measures has FPL failed to screen?

A: FPL has failed to screen 52 C/I lighting measures specified in the Commission's Fourth Procedural Order. The only screening analysis of C/I lighting measures identified in FPL's documentation is a single analysis of FPL's existing C/I lighting program.

3. *Two-Year Payback Screen*

Q: What is FPL's rationale for rejecting measures with less than a two-year payback?

A: First, FPL believes that if the payback is less than two years, the measures "will be implemented by customers without stimulus from the utility," and that therefore a payback limit will reduce free-ridership (IR People's Gas System Revised 1-12, p. 15). In addition, FPL contends that this screening criterion is appropriate because it is consistent with the design of the Florida Energy Office's Institutional Conservation Program (ICP), which FPL says will not fund measures with less than a two-year payback (CEGRR, p. 20).

Q: Are FPL's stated concerns about free-ridership sufficient justification for rejecting measures based on a two-year payback rule?

A: No. First of all, FPL has made no showing that investments with paybacks of less than two years will be made without utility intervention.[33] To the

[33]FPL's explanations of the free-ridership concerns are mutually inconsistent. FPL suggests both that all measures with paybacks under two years will be installed without utility rebates,

contrary, FPL recognizes that "customers do not always make decisions based on economic reasons" (Hugues, p. 44).

Even the payback curves used by FPL indicate that a substantial percentage of customers will not install measures with a two-year payback, even in the long term. FPL's sample payback curves indicate a non-acceptance rate of 40% for commercial measures, 30% for residential measures and 55% for residential appliances (CEGRR, p. 26).[34] These fractions would be much higher for groups facing major market barriers, including low-income consumers, renters, and others with limited information, capital, or time, or facing institutional barriers.[35]

The "Commercial/Industrial Customer Cross-Section" market research survey that FPL conducted in 1986 indicated that 9.7% of those customers had "no money for energy investment," 24.5% had funds but required a payback under one year, 23.4% had payback requirements between 1 and 3 years, and 28.4% did not know their payback threshold. Assuming that the customers with 1–3 year paybacks were even evenly distributed in that range,

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implying that a program to deliver this measure would have 100% free riders; and that free-ridership would be less than 100%, but excessive, for these measures. Mr. Hugues defense of this screening rule is limited to the observation that free-ridership "would be higher" if measures with quicker paybacks were included (Hugues, p. 31). This is hardly an acceptable excuse for foregoing the benefits of all measures with paybacks under two years, especially given FPL's concerns about achieving a fair distribution of DSM benefits.

[34]These payback curves are not specific to measures or market segments, and hence do not reflect the differences in payback requirements for different measures by different customers in different circumstances.

[35]Even measures with negative capital costs, such as improved HVAC system design, may not be implemented due to institutional and market barriers (e.g., split incentives between developer, architect, engineer, and tenant).

46% of respondents indicated that they required paybacks under 2 years. If the "don't know" group was similar to the respondents who did know their payback requirements,[36] about 64% of the customers would have payback requirements under two years.

In addition, if FPL believes that measures with paybacks of less than two years will be installed without utility intervention, consistency requires that the resulting kW and kWh reductions be reflected in the load forecast. ~~Since~~ FPL has not demonstrated that increased energy efficiency has been adequately taken into account in its load forecast. Least-cost planning must be based on a realistic and consistent load forecast.

Q: Do you think that FEO's Institutional Conservation Program is an appropriate model for FPL's DSM goal-setting?

A: No. The FEO ICP may be budget-constrained and therefore not at all comparable to the utility DSM efforts being considered in this proceeding. Furthermore, the federal regulations and the ICP training manual, which define the ICP, contradict FPL's position. They specify that a minimum payback requirement of two years is appropriate only if measure selection is based on simple payback. If instead the funding decisions are based on life-cycle cost analysis (as under the Commission's approved methodology), the ICP regulations specify that the benefit-cost ratio, with no minimum payback restriction, should be the basis for approving measure funding (IR LEAF 2-35).

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[36]This seems optimistic, since those least likely to know would be the representatives of cash-constrained or bureaucratic organizations that rarely make efficiency investments.

Q: Have you identified other problems with FPL's application of a two-year payback limit?

A: The first screening applied this simple payback standard based on the *technical* potential savings per participant of a single measure, without considering interactions with other measures. Yet achievable potential, not technical potential, determines the financial attractiveness of the measure. Therefore, it is possible that for some cost-effective measures rejected in the first screening, simple payback based on *achievable* potential rather than technical potential will exceed two years.

Adjustments to savings due to interactions with complementary measures can be significant. For example, interaction with RSC-21A (High Efficiency Central A/C) reduces the assumed summer peak kW and kWh savings of measure RSC-5A (Reduce Duct Leaks) by more than 20% (Hugues Document 11, p. 2). In addition, FPL performs this screen only for average conditions. Paybacks will vary with the level of usage and other factors.

B. Cost-Effectiveness Analysis Methodology

Q: In what ways do FPL's cost-effectiveness methodology and avoided costs affect the projection of achievable potential in 2003?

A: In two basic ways. First, the screening process selects the DSM options included in the projection of achievable potential and consequently considered in resource integration. FPL's first and second screenings eliminated many options from further consideration.

In addition, for the RIM scenario, the cost-effectiveness methodology and avoided costs also affect achievable potential by affecting the size of the incentive permitted under the RIM test. Under the RIM scenario, FPL sets rebates at the lesser of (1) the rebate that results in a RIM test ratio of 1.0 and (2) the rebate yielding a payback of two years. For measures where the test ratio is the constraint, higher avoided costs would allow for higher rebates, resulting in quicker payback and higher achievable potential for the measure.

Q: What problems have you identified in FPL's analysis that result in underestimating the cost-effectiveness of DSM?

A: FPL's measure screening undervalues DSM for the following reasons:

- The second screening overstates the costs of reinstallation and neglects many of its benefits.
- For some measures, measure interactions based on STEP I screening results may be the basis of inappropriate reductions in the measure savings per participant assumed in the second screening.
- The measure screening fails to consider the effects of timing of DSM installations on cost-effectiveness.
- FPL inappropriately allocates program administration costs to measures.
- FPL evaluates the cost-effectiveness of measures only for average savings, based on average consumption, rather than for a range of situations.
- The measure screening relies on an under-estimate of avoided costs.

These problems (and probably others that I have not been able to identify, due to the poor documentation) lead to such peculiar and counterintuitive outcomes as the rejection of all fuel-switching measures and of all water-heating measures.

Q: Why did options that passed the first screening fail in the second screening?

A: The second screening re-installs each measure at the end of its useful life whenever the measure life is shorter than the 23-year analysis period. According to FPL, the added equipment and administrative costs associated with re-installing measures accounts for the rejection of measures that had passed the first screening (CEGRR, pp. 34-35).

Q: Is it reasonable to expect measure replacement to have this effect on screening results?

A: No. It does not seem likely that a measure found to be cost-effective when considered over the life of the first installation would become uneconomic when the costs *and benefits* of a re-installation of the measure are included in the analysis. FPL's result is counter-intuitive, since DSM equipment and program costs are projected to escalate more slowly than the avoided-cost benefits. If, as FPL claims, rejections in the second screening are due to the costs of measure replacement, they are most likely a result of an incorrect modeling of re-installation of measures.

Q: What errors in FPL's modeling of measure replacement account for the rejection of measures in the second screening?

A: The second screening analysis includes the costs of the reinstallation, but omits many of the benefits. For example, many of the TRC options rejected in the second screening have an expected life of 10 or 20 years, and are therefore re-installed in 2015 only 1.5 years before the end of analysis period. As a result, for these measures, FPL's evaluation reflects the front-end costs of the replacement, but only 1.5 years of benefits out of a measure life of 10 or 20 years. Costs must be matched with their benefits to ensure fair comparisons for the full lifetime of the measures under analysis.

FPL also errs in assuming that the replacement measure costs will be the same (in real terms) as the first installation. The analysis therefore ignores the effect of technological improvements on the future cost of a measure. As recognized in the FEO study, "increased adoption of currently available technologies [may lead] to manufacturing efficiencies that reduce per unit production costs (SRC Report No. 7777-R8, p. I-7).[37]

Q: What is FPL's rationale for cutting off the cost-effectiveness analysis at 2016 instead of the end of the measure life?

A: FPL indicates that it established a cutoff point of 20 years after the installation of the avoided CT to satisfy the Commission's conditions for the use of the revenue requirements methodology. FPL explained that by reinstalling measures, it extended the demand reductions twenty years to match the life of the avoided CT (Admission LEAF 1-24; Deposition 4/13/94 and 4/14/94, pp. 21). Otherwise, it would have to apply the value-of-deferral method.

In addition, FPL had claimed that if instead it used a value-of-deferral analysis, it would "only lower the amount of DSM that is cost-effective." (March 14, 1994 Response of FPL to LEAF's Motion for Continuance, p. 8). FPL later retracted this claim when its own analyses contradicted it.

Q: Has FPL provided adequate justification for cutting off the analysis before the end of the measure life?

A: No. As the Deposition Exhibit 2 clearly demonstrates, FPL's method biases the analysis. In each of the nine cases examined, the application of the value

[37]Once the efficient equipment becomes more standard, the program costs associated with encouraging reinstallation should decline and equipment costs should be less.

of deferral method (for the life of the measure) produced a higher TRC ratio than did FPL's revenue requirements analysis. FPL has since admitted that its revenue requirements analysis results in lower TRC benefit-cost ratios (Letter from Charles A. Guyton to Chairman Deason, April 15, 1994, p. 1).

The Commission correctly found that if the analysis matches measure life with avoided unit life by re-installing measures, the revenue requirement method can produce accurate results. As the Commission stated,

> [FPL's measure replacement] is similar to performing a 30 year avoided unit analysis and comparing two heat pumps against the supply side option, one heat pump for the first fifteen years, its useful life, and a second for years 16–30. (Order Denying Motion for Continuance, p. 6)

However, the analysis that the Commission described and approved in its Order is not the analysis that FPL performed. FPL compared the costs of 20 years of the 30-year life of the avoided CT to the cost of two successive installations of 20-year measures (in 1995 and 2015), the installation of three 10-year measures, four installations of 7-year measures, etc.

Q: What change in FPL's analysis do you recommend to correct this faulty modeling of measure re-installations?

A: It is possible to re-install measures to match the useful life of DSM with the life of the avoided supply, but the better option would be to use the value-of-deferral method.

Q: Are there other reasons why options failed in the second screening?

A: Perhaps. Some options may have failed in the second screening because the assumed kW and kWh savings were adjusted to reflect measure interactions. In addition, according to Dr. Sim, both screens followed the Commission's approved cost-effectiveness methodology, but the first screening was less accurate than the second (Deposition, 4/13/94 and 4/14/94, pp. 47-48).

Without documentation, it is not possible to identify or evaluate differences in input assumptions and methodology.

Q: Has FPL appropriately adjusted measure savings in the second screening for measure interactions?

A: No. Screening of measures included in programs *should* take into account measure interactions. However, certain measure savings assumed by FPL in the second screening may reflect adjustments for interactions with measures that were not actually included in the resource plan.

Q: How could rejected measures have affected the measure savings assumed in the second screening?

A: FPL calculated measure-specific achievable potentials in STEP II of the four-step screening process, after the first screening (STEP I) but before the second screening (STEP IV). There are at least three groups of measures, not forwarded to integration after STEP IV, that may have been included in the STEP II analysis and, as a result, may have affected the kW and kWh reductions assumed for measures in the second screening:

- UP measures passed in the first but rejected in the second screening, or "failed at initial IRP screening" (as specified in the Hugues testimony, Exhibit No. Document 9).
- CUE measures passed in the first screening. Although these measures were not included in the resource plan, they were apparently included in the evaluation of achievable potential (Hugues testimony, p. 10).

- UP measures rejected in the first screening, but mistakenly sent on to the System Planning Department by the Marketing Department. As explained by Mr. Hugues (Deposition 4/21/94, p. 151),

> I think it has to do with the fact that we, in marketing, made a mistake and gave Doctor Sim and his folks more measures that they had to analyze as far as running CPF runs, and consequently they just ran them all and it got filed inadvertently.

Without documentation it is not possible to determine whether these measures were analyzed in STEP II of the screening process in conjunction with the measures screened in STEP IV.

Q: Have you been able to confirm that FPL incorrectly adjusted measure savings for interactions with rejected measures?

A: No. As stated earlier, FPL has not documented its analysis of measure interactions.

1. Timing of Measure Installations

Q: How has FPL failed to consider the effect of the timing of DSM investments on cost-effectiveness?

A: In its initial four-step screening process, FPL's analysis considers only measures first installed in 1995, when in fact under FPL's proposed goals, DSM will be installed throughout the planning period.

Q: Will DSM be more cost-effective if it is installed in later years?

A: Yes, probably. As long as the benefits escalate faster than costs, measures will be more cost-effective if installed in later years. In particular, in the case of FPL's analysis, measures installed in 1995 receive no generation capacity credits for the first two years of their expected life, whereas measures installed in 1997 and later would avoid generation capacity starting in the first year of measure life. FPL's projected avoided fuel costs also grow faster than inflation.

2. *Inclusion of administrative costs in measure screening*

Q: What administrative costs did FPL include in cost-effectiveness analysis of DSM measures?

A: FPL allocated to individual measures utility *program* implementation and delivery costs, including payroll, training, advertising and promotion expenses. FPL based its estimates of administrative costs per participant on its experience with existing FPL programs.

Q: What is FPL's rationale for including program administrative costs in the cost-effectiveness analysis of single measures?

A: FPL contends that it "cannot meaningfully and/or accurately analyze the cost-effectiveness of a DSM measure without regarding it as a *delivered* or *implemented* measure" and "until the costs of delivering or implementing the measure...are projected" (IR LEAF 2-50). Therefore, FPL treated each measure as a single measure program:[38]

> In essence, FPL projected costs for a "program" designed to implement a DSM measure.... With the addition of these costs there is little or no distinction between a measure and a program.

FPL asserts that its purpose in including administrative costs in measure screening is to ensure that the ultimate DSM goals are based on economic

[38]In FPL's analysis, a program does not even consist of a single measure; FPL's "programs" are subsets of a single-measure program, which differ by rate class and incentive level.

programs and measures. As stated in a letter of March 24, 1994 fro, Charles Guyton (on behalf of FPL) to LEAF:

> ...FPL believes that the analysis of measures used to establish goals should include program administrative costs, and it has included such costs in its cost-effectiveness analyses, as it properly should. Otherwise the goals established could be unachievable.

FPL also claims that including administrative costs in measure screening is consistent with Commission methodology (testimony of Hugues, p. 28).

Q: Is FPL correct that the fixed costs of delivering and implementing the measure must be included if the measure screening is to be meaningful and accurate?

A: No. As I explained earlier, allocation of joint program costs and overheads to individual measures can make cost-effective measures appear uneconomic. Measures that look uneconomic under FPL's methodology may in fact be economical when combined in a program, whose fixed delivery costs can then be distributed over numerous measures.

Q: Do you believe it is appropriate to include uneconomic measures in DSM programs as long as the program as a whole is cost-effective?

A: No. Only measures with incremental benefits exceeding incremental costs should be bundled into programs.

Q: Does FPL recognize the importance of the distinction between measures and programs?

A: No. On the one hand, FPL does acknowledge that there are economies in bundling measures into programs. In deposition, Mr. Waters (Deposition, 4/4/94, p. 88) presented the following example:

> ...if all the water heater measures had passed the RIM, we would not come to the Commission, I don't believe, and petition for approval of four separate programs; one for the piping, and one for the low flow shower heads, and all of that. We would combine them into a single program. The cost structure for that single program should look very like the combination of the measures when you analyze, but still it makes more sense than to have one person go out there and implement versus what we may have assumed in the other one as one-fourth of a person when we did the analysis.

On the other hand, FPL takes the position that under its allocation of program costs to measures, administrative costs are additive and, as a result, bundling the four water heating measures into a single program will not alter the cost-effectiveness of the measures or of the program (Deposition, 4/4/94, p. 69]. FPL claims its assignment of program costs to measures takes proper account of the distinction between measures and programs. According to FPL, the allocation "did not assume that each measure would be a separate program, administered individually." (CEGRR, p. 19).

FPL's assurances to the contrary notwithstanding, its assignment of utility costs to measures does not ensure a meaningful screening of measures or an accurate estimate of the cost of programs.

Q: Please explain why FPL's allocation of program costs to measures cannot result in a meaningful measure-level analysis.

A: FPL's explanation of its allocation of program costs to measures brings into focus the Company's fundamental misconception. In a program that consists of four water heating measures, FPL would allocate one-fourth of the installer's travel time as well as the incremental installation time to each measure, when in reality, the installer must travel to the site regardless of the number of measures installed.

FPL assigns the same administrative cost per participant to many measures of different types, for customers from different rate classes, of different equipment and installation costs, of different kW and kWh savings potential. For example, an administrative cost of $43 is assumed for all residential HVAC measures; the value is the same for a $2,253 residential heat pump measure as it is for an $87 programmable thermostat (Hugues, Exhibit Document 6, p. 1). There is no reason to believe that it is equally complicated to administer measures that have substantially different costs. It is likely that FPL has overstated administrative costs in its measure screening, in general, but more important, the allocation of the same administrative costs to measures of very different costs will tend to bias the measure screening against lower cost measures.[39]

Q: Is it possible under FPL's methodology to develop a per-measure cost for use in measure screening that ensures an accurate estimate of total program administrative costs?

A: No. To do so, FPL would have to know the results of the measure screening, in particular, the measures selected and the participation projected, before the measure screening was even performed.

Q: What was the basis for FPL's estimates of administrative costs?

A: FPL claims that its estimates are based on actual FPL program costs, but has not specified the actual data and calculations employed.[40]

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[39]SRC treats administrative costs on a cents-per-kWh basis and is therefore less likely to bias the screening analysis.

[40] Originally the Company claimed that it relied on the FEO study for many of its C/I programs (Hugues testimony, p. 27 and Exhibit No. Document 6). It was not until April 22 that Mr. Hugues disclosed (4/22/94 Deposition, p. 32) that the references to the FEO study were

Q: Are existing FPL programs an appropriate basis for the estimate of administrative costs per measure?

A: No. FPL's reliance on experience with existing programs assumes that there is no room for improvement in its DSM implementation. To the contrary, FPL's existing programs are inefficient, offer low incentives, and attract low participation. Therefore, it would come as no surprise that these programs have high administrative costs. Better program design and higher incentives are likely to lower administrative costs per participant.

Q: Does the Commission's Cost-Effectiveness Manual instruct utilities to include program administrative costs in the screening of single measures?

A: No. The manual discusses only the screening of programs, not of measures.

3. Screening Based On Average Use

Q: What is wrong with evaluating the cost-effectiveness of measures only for average consumption levels?

A: As SRC recognized, conservation technologies that are not cost-effective at the average consumption level may be economic for high-use customers (SRC Report No. 7777-R8, p. I-7). SRC cites solar water heating as an example:

> For example, domestic water heating loads in Florida are, on average, quite small resulting in long paybacks for solar water heating. But solar water heating may have reasonable paybacks for particular segments with higher-than-average consumption.

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incorrect, even though the error had been discovered "[m]aybe a couple of weeks ago or so" previously xx.

The low average water heating consumption may account for FPL's rejection of all water heating measures. If FPL had also screened these measures at higher consumption levels, some may have been found to be cost-effective. A measure need not be universally applicable to be included in a program. It need only be cost-effective enough to be worth on-site screening, to reflect site-specific usage, installation cost, operating schedule, and measure interactions.

C. Avoided cost

Q: To what extent have you been able to review FPL's avoided-cost estimates?

A: My review has been hampered by inadequate documentation. FPL frequently misinterpreted discovery concerning avoided costs, responding with information about the EGEAS runs in the integration stage of the process, even though EGEAS was used to compare resource options and resource plans, not to derive the avoided costs that were input to the cost-effectiveness analysis (as acknowledged in IR LEAF 1-13). For purposes of this testimony, I am assuming that FPL's avoided costs and EGEAS integration runs make consistent assumptions.

In addition, FPL totally failed to document the avoided costs assumed in the first screening. According to Dr. Sim, the first screening employed a methodology "virtually identical to the Commission's approved methodology," "within a 5 percent accuracy range" (Sim deposition, pp. 47–48). Apparently the only difference in methodology between the first and second screening is some unspecified difference in "the total system fuel impact calculation" (Sim deposition, p. 50).

My comments on FPL's avoided costs refer specifically to the second screening, as documented in Appendix K. Depending upon the actual differences between the first and second screenings, my comments on avoided costs may or not apply to the first screening.

Q: What deficiencies have you identified in the Company's avoided costs?

A: FPL's avoided cost modeling will undervalue DSM because of the following errors and omissions:

- There are inconsistencies between avoided energy and avoided capacity costs ~~supply~~
- The analysis neglects costs of compliance with the Clean Air Act Amendments.
- FPL's analysis understates avoided T&D
- The analysis understates avoided energy losses.
- The analysis omits environmental externalities.
- The analysis gives DSM no credit for risk mitigation.

1. Generation

a) Inconsistency between Avoided Energy and Avoided Capacity Costs

Q: What generation capacity is avoided by DSM in FPL's cost-effectiveness analysis?

A: FPL assumes that the only generating capacity that DSM will avoid is CT capacity first needed in 1997.

Q: In what way are FPL's avoided energy cost estimates and avoided capacity cost estimates inconsistent?

A: In the computation of avoided energy costs, it appears that FPL adds baseload plant to the dispatch to keep down avoided cost, but in the estimate of avoided capacity cost, does not allow DSM to avoid the higher fixed costs of fuel-saving plant.

If FPL had assumed an all-CT expansion plan in estimating both avoided energy and avoided generation capacity costs, it would have developed consistent estimates of these two avoided cost components. Likewise, if in reflecting baseload plant in the computation of avoided energy costs, FPL had also permitted DSM to avoid some of the fixed costs of combined-cycle (CC) and coal capacity additions, then it could have developed consistent estimates of generation capacity and avoided energy costs.

However, it appears that FPL assumed the addition of fuel-saving plant, namely CCs and coal plants, in its computation of avoided marginal fuel costs, while at the same time assuming an all-CT expansion plan in its estimate of avoided generation capacity costs.

Q: What evidence do you have that avoided marginal fuel costs reflect the addition of baseload plant ?

A: In response to a data request for all new capacity additions assumed in the avoided cost calculation, FPL refers to the three competing resource plans considered in the resource integration stage of FPL's planning analysis (LEAF 1-19). According to the CEGRR, FPL's "supply-only" expansion plan consists of combined cycle (CC) units and coal plants, as well as CTs. If FPL's response to discovery can be relied upon and the "supply only" plan was indeed the plan assumed in the avoided cost calculation, then it is clear that the avoided marginal fuel cost estimates reflect the additions of CC and coal units.

The avoided cost data inputs to the cost-effectiveness analyses confirm that fuel-saving plant is being added to the dispatch. The average heat rate implicit in the estimates of avoided marginal fuel cost remains fairly constant over time, despite load growth and the effects of CAAA compliance on plant operating efficiency, an indication that new baseload plant is being added to the dispatch. FPL's rerun of the cost-effectiveness analysis assuming the installation of a CC instead of a CT (Deposition Exhibit 2) provides additional confirmation. In this rerun, the addition of a baseload unit probably accounts for the dramatic decline in the capacity factor of the CC unit in 2006 (Deposition Exhibit 2, PSC Form CE 2.1, "Avoided Gen Unit Fuel Cost").

Q: Is the substitution of a 1997 CC for the 1997 CT (as in the re-calculations presented in Deposition Exhibit 2) a solution to the inconsistent mix of assumptions in FPL's avoided energy and generation capacity cost analysis?

A: No. Avoided generation cost should reflect the difference in costs between the least-cost supply plan with the DSM and the least-cost supply plan without the DSM. The installation of a CC in 1997 is not contemplated in FPL's Supply-Only Plan. As FPL (CEGRR, p. 66) explained,

> On FPL's current system, a CT unit is *not* the desired economic choice, but it is the most likely "FPL-build" option in regard to the time necessary to construct and license a unit by 1997.

According to FPL's Supply-Only Plan (as presented in the CEGRR), it would be more appropriate to model an additional increment of DSM as follows: DSM avoids CT capacity in 1997 and higher cost CT capacity (Phase I of a staged CC unit) in 1998, then delays CC capacity until 2002, at which time the CC unit is built and coal capacity is avoided, and so on.

Q: Does the Commission's methodology preclude consideration of multiple avoided generating units?

A: No. FPL claims that the Commission's methodology forces it to compare a single measure against only one generating unit (IR LEAF 1-9, p. 2). However, nothing in the Commission's methodology prevents a realistic application of the deferral methodology. The Commission gives the utilities wide leeway in developing their cost-effectiveness method, which FPL takes advantage of elsewhere in its analysis.

b) Treatment of Environmental-Compliance Costs

Q: What environmental-compliance costs has FPL included in avoided costs?

A: According to its responses to discovery, FPL has excluded CAAA-compliance costs, including SO_2-allowance costs (IR LEAF 1-29).

Q: What is FPL's rationale for excluding compliance costs from its avoided cost estimates?

A: FPL's response to LEAF 1-29 states:

> Many of the regulations which are required by the Clean Air Act Amendments are still being developed. Likewise, FPL has not yet received a final official notice as to how many SO_2 allowances it will be receiving.
>
> For these reasons, it is not possible at this time to accurately determine what compliance actions FPL will need to take nor what costs—if any—associated with these actions will be. Therefore, the magnitude of the potential compliance actions and costs for "installation and operation of pollution control equipment, fuel switching, (and) scrubbing" theoretically ranges from zero (i.e., none of these listed actions are necessary and no associated costs are applicable) on up.

> FPL needed to make an assumption about these types of compliance actions and costs for the IRP analyses performed for this docket which [sic] fell within this theoretical range. The assumption was made that no such compliance actions or costs would be needed.

Q: Is this a reasonable justification for omitting all environmental-compliance costs in screening DSM?

A: No. FPL knows that it will face some environmental compliance costs, either to reduce emissions or to internalize them, and knows that it faces a range of costs for compliance with other environmental requirements. Setting these foreseeable but uncertain environmental cost to zero is akin to setting future fuel costs to zero because *they* are not known with certainty. Uncertainty is not a legitimate justification for ignoring a cost. Everything in the future is uncertain.

Q: What are the costs that FPL is likely to face that would affect avoided costs for DSM screening and integration?

A: While FPL faces several costs from the CAAA that are not likely to be avoidable through DSM (such as continuous emissions monitors and installation of low-NOx burners on existing units), at least two sets of costs do affect avoided costs and the value of DSM.

First, under Title IV of the CAAA, FPL will need one SO_2 allowance for every ton of SO_2 its plants emit. FPL may partially adapt to this situation by burning lower-sulfur fuels (or scrubbing, as is planned for Manatee if it burns Orimulsion), which will generally increase avoided fuel costs. Even after plants are switched to low-sulfur fuel, every MWH reduction in the generation from fuel with any sulfur content will reduce sulfur emissions. Any reduction in sulfur emissions will allow FPL to buy fewer allowances or free up allowances for sale in the allowance-trading market. Contrary to

FPL's position, whether FPL has a surplus or a deficit of allowances is irrelevant to the determination of avoided cost.

Second, FPL acknowledges that its steam-plant heat rates will increase by 10 BTU/kWh with the installation of low-NOx burners required by Title I and IV of the CAAA (IR LEAF 1-28). In addition, EPA has classified over-fire air (OFA) as part of low-NOx technology, and FPL expects OFA to result in further increases in heat rate of 15-25 BTU/kWh at various plants, as well as auxiliary power use of another 10-15 BTU/kWh, plus reductions in net output and increased O&M, some of which may be variable O&M (IR LEAF 1-28).

Q: What other environmental compliance costs are currently foreseeable?

A: Some control requirements are likely for mercury from utility boilers, depending on the outcome of pending EPA studies. Even if mercury-emission limits are imposed only regionally, controls are likely for Florida, due to the environmental sensitivity of the Everglades.

Similar studies are under way for other toxic heavy metals, which are released in significant quantities by coal and oil plants, in proportion to their fuel consumption, and may require pre-cleaning of fuels or scrubbing of flue gases (SO_2 scrubbers remove some, but not all, heavy metals). The general air-toxics requirements of Title III of the CAAA were not immediately imposed on utilities, which were already heavily burdened by the acid-rain and ozone provisions of the act. Extension of the controls on other sources to utilities seems likely.

The third category of avoidable compliance costs is greenhouse gases, especially CO_2, which is released in the combustion of all fossil fuels. Voluntary measures do not at this point seem to be bringing the United States towards compliance with the goal of keeping emissions in the year 2000 below 1990 levels, so some mandatory measures will likely be required.

Q: What environmental compliance costs should be included in FPL's avoided costs?

A: The variable costs of scrubbers, lower-sulfur fuels, and low-NOx burners should be included in dispatch costs, as should change in SO_2 allowances for the avoided fuel mix. The avoided costs should also include some central or expected-value estimate of the cost of future restrictions on emissions of mercury, other heavy metals, and CO_2.

2. *Avoided Transmission and Distribution*

Q: What avoided transmission and distribution costs did FPL assume in its avoided costs used in screening DSM?

A: FPL credited some energy-efficiency measures for residential and small general service (GS) customers with capital cost savings of $100/kW for transmission and $50/kW for distribution, and O&M of $3.20/kW-yr for transmission and $14.93/kW-yr for distribution, all in 1994 dollars (IR LEAF 1-16, 17). Load management for these customers was assumed to save 60% of the T&D saved by energy efficiency.

Q: What problems have you identified in FPL's treatment of avoidable T&D costs?

A: I have identified four groups of problems. First, the avoided-cost estimate for distribution capital cost is far too low. Second, the avoided-cost estimate for transmission capital cost is also too low. Third, FPL unreasonably assumes that the loads of large customers (GSD, GSLD-1) and some DSM measures for small customers do not affect T&D costs. Fourth, FPL appears to overstate the value of T&D savings for load control, as compared to conservation.

a) Understatement of Avoided Distribution Costs

Q: What is the basis of FPL's estimate of avoided distribution costs?

A: FPL's $50/kW estimate of avoided distribution costs appears to be taken from *Impact of Demand-Side Management on Distribution Planning* (provided in Document Response No. 29, p. 607378–607438). This document appears to be the 1991 study "by Ian Nichols, a distribution engineer for New South Wales (Australia) who was 'on loan' to FPL," as described in *The Evolution of Projected Benefits of DSM on Transmission & Distribution Expenditures at FPL* (Document Response No. 28, p. 607310). This study used data from 1987-89 on distribution investments and load growth, and estimated that energy conservation would save $46/kW in distribution capital costs, apparently in 1988 dollars. Including inflation, this is equivalent to $55–60/kW in 1994 dollars. It is not clear how this value was reduced to $50/kW.[41]

Q: Is this a reasonable estimate of the avoided distribution costs?

[41] *The Evolution of Projected Benefits of DSM on Transmission & Distribution Expenditures at FPL* interprets the Nichols result as $50/kW, without specifying the year's dollars in which the costs are stated. Evolution also reports a site study that found avoided distribution costs of $30–60/kW and vaguely describes adjustments to the site study (including the spurious assertion that no distribution project could ever be deferred for more than five years), resulting in a "generic" estimate of $21/kW. This lower value is not documented and does not appear to have been used in FPL's CEGRR filing or goals.

A: No. The $50/kW capital cost is derived from FPL's estimate of just one of three types of costs, and includes only a portion of that type. The overall estimate is understated for eight reasons:

First, the Nichols study assumes that only substations and portions of primary feeders are avoidable due to energy efficiency improvements. All service upgrades, secondary lines, transformers, and primary feeder laterals are classified as "Type 1" or "revenue work" to serve new customers or new loads for existing customers. FPL assumes that it would never do anything to reduce this load growth, and thus that the "revenue work" is unavoidable. FPL does recognize that "revenue work" is required to accommodate load growth due to sales programs, and estimates the cost of this portion of the distribution system to be $238/kW for residential customers, $315/kW for GS, $165/kW for GSD, and $54/kW for GSLD-1, all in 1988 dollars.[42] Nichols (p. 60) also acknowledges that some "system improvements" (which he intended to treat as avoidable) were classified as "revenue work," understating the distribution credit for conservation.

Second, FPL excluded a group of "Type-3" costs, many of which appear to be related to load. Type-3 costs include investments for

- Reliability, such as feeder ties. These investments are driven by the number of feeders and the load on each feeder.
- Relocations, such as moving feeders for highway widening. These investments vary with the number, size, and complexity of installed

[42]These values are understated, for reasons discussed below.

facilities; an allowance for the present value of future relocations should be added to the costs of added facilities.[43]

- Deferred improvements, such as switches and control devices, that were not installed at the time the line was built. These deferrals are sometimes intentional—because the initial load on the line or substation is too low to justify additional protective devices—and sometimes due to technical progress and the availability of better equipment. The first class of deferred investments is directly related to load growth, while the second is a continuing cost of maintaining a distribution system to changing technical specifications, with future costs analogous to the costs of future relocations.

The Nichols study does not provide much information on Type-3 costs, but it appears from p. 56 that Type-3 costs may total $141/kW, of which some portion is load-related and avoidable.

Even the "Type 2" substation and feeder costs that Nichols treats as avoidable are understated due to several aspects of the analysis, each of which either understates the costs, overstates the associated load growth, or reduces the effectiveness of conservation in avoiding costs.

Continuing the list, the third source of understatement of distribution costs is that FPL excluded costs for "conversion work in networks with growth rates above 8%...because FPL has predetermined that it is cost-effective to carry out this work as soon as possible" (p. 45).[44] This exclusion

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[43]A similar allowance for "capital additions" is usually included in the evaluation of major power plants, especially nuclear and coal plants.

[44]It is not clear what Nichols means by "conversion" (which might just be voltage increases, or might include other capacity-expansion options), why conversion is

seems improper, since active DSM programs, especially those focused on new construction, could reduce load growth on these fast-growing networks below 8%, so that conversion would no longer be cost-effective or necessary. In any case, if these costs are excluded from the analysis, the associated load growth met by the conversion should also be subtracted; Nichols seems to have included all the load growth, but only some of the costs. Many networks must have load growth over 8%, since Nichols reports that the networks receiving improvements in 1987-89 in FPL's Southern Division average 12.3% growth and those in other divisions average 6% to 7.7%. The exclusion of many costs related to high-growth areas (but inclusion of their load growth) may explain the low costs Nichols finds for the Southern Division, which are just 42% of the next-lowest division (p. 49).

Perhaps due to this exclusion, or perhaps due to other errors, Nichols substantially understates the costs of distribution additions. For substations, Nichols reports avoidable substation additions of $19 million annually for 1987-89. According to FPL FERC-Form-1 data, distribution-substation additions in this period averaged $36 million, or almost twice as much as the additions identified by Nichols. FPL ignored almost half of its additions in this category.[45]

"predetermined" to be cost-effective, or how many dollars are affected by this exclusion. Nichols's use of the term "network" is also unclear, since I would expect that most of the FPL distribution system would be in a radial configuration, not networks. I assume that Nichols uses "network" to mean one or a few substations and their associated intertied feeders.

[45]This comparison cannot be made for other FERC accounts, since FPL distribution categories do not match the FERC accounts.

Fourth, Nichols understated distribution costs by ignoring all customer contributions, since he was only interested in avoided costs for the RIM and utility tests.[46] He notes that these contributions *are* avoided costs for the TRC test, and should be added back in (pp. 47 and 60). He estimates that customer contributions average $61/kW (p. 56).

Fifth, FPL's study overstated load growth, which produces an unrealistically low avoided cost per kW of load growth, as Nichols observes.[47] This overstatement appears to arise from some combination of

- The assumption that load growth associated with substation capacity additions is equal to the station's "prior emergency firm capacity" times the regional load growth rate (presumably a percentage value). The substation's emergency rating will typically include some load that it would have to pick up from another substation in an emergency (loss of the other substation or one of its feeders), and will therefore be higher than the peak load of the area normally served by the substation.[48]

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[46]This example illustrates well the bankruptcy of the RIM test, which would prefer an option that required a $500 customer contribution (not a RIM cost) to one that required a $100 utility expenditure (which would be a RIM cost).

[47]"The total area network loads determined for each division...multiplied by the estimated load growth rates are often greater than the load growth predicted for the division as a whole" (p. 60). "An estimate of the degree of over-estimating network load growths in project work could significantly increase the benefits assigned to conservation and direct load control programs" (p. 61).

[48]For the Crane third feeder (project 7163), Document Request No. 36 reports pre-expansion emergency-feeder ratings totaling 80.7 MVA and total load of 55.5 MVA.

- The use of feeder and substation non-coincident peak (NCP) loads and load growth. Since feeders and substations peak at different times, the sum of their NCPs will be higher than system coincident peak.
- The load growth assumed in the planning-and-necessity (P&N) reports for each feeder used in the study appear to be higher than the growth "predicted for the feeders in the substation by substation division forecast...[which] appear to be balanced with the load growth rate that is forecasted for the division as a whole and therefore should more represent the true load growth rates" (p. 61).[49] In other words, FPL distribution planners overstate load-growth forecasts when determining whether feeders should be upgraded; this may be a useful conservatism in distribution planning, but overstates the amount of growth ~~the~~ that drives each investment. Only a little load growth is sufficient to prod the distribution planners to upgrade capacity, with a comfortable margin of error.
- The conversion from the higher MVA load values used in distribution planning to MW values used in DSM screening. Nichols does not discuss this conversion, so I cannot tell whether it was performed properly.

Seventh, the Nichols study understated the portion of DSM that would contribute to avoided distribution costs. Nichols multiplies the avoided cost for the networks that were upgraded in 1987-89 by the fraction of system load served through those networks, which is only about 50%. This computation implicitly assumes that the networks not expanded in 1987-89

[49]These P&N reports referred to in the Nichols study may be the Purpose and Necessity reports provided in Document Request No. 36.

would never need expansion, and would never be able to pick up load transferred from fast-growing neighboring networks, so any DSM on those substations would be wasted (in terms of distribution savings). In reality, distribution upgrades are lumpy, and expansions may be needed only every five or ten years.[50] Unless a significant portion of FPL's distribution system is permanently over-built, Nichols estimates should be doubled to reflect the benefits of DSM on all distribution circuits.

Eighth, and finally, while Nichols recognizes that DSM targeted at high-growth areas would be more valuable than the average value he computed for evenly-distributed savings, FPL does not take this factor into account in screening DSM options, such as new construction, that would be concentrated in high-growth areas.

Q: Have you attempted to independently estimate avoided distribution costs for FPL?

A: Yes. Following the methodology specified in the NARUC cost-allocation manual, I performed a regression of FPL net distribution additions (excluding street lighting, services and meters) against summer peak kW for the period 1982 to 1994.[51] As shown in Exhibit ____ (LEAF-PC-3), the resulting

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[50]For example, consider a hypothetical substation with two transformers and four feeders that was expanded in 1986 to three transformers and six feeders, for a 50% increase in capacity. At a 4% growth rate, the new capacity would cover up to 10 years of load growth, depending on how evenly the load was distributed. Hence, new capacity would be avoidable at that substation by 1996, even though no improvements were needed during 1987–89.

[51]National Association of Utility Regulatory Commissioners. 1992. *Electric-Utility Cost-Allocation Manual."* Washington:NARUC. Since we did not have retirements and additions separated out for 1983, I assumed that retirements in 1983 were the average of the retirements in 1982 and 1984. To reflect inflation from the time plant was added until it was retired, I effectively doubled the book value of retirements, which implies a dollar-weighted average life

marginal capital costs are $350/kW in 1992 dollars or about $375/kW in 1994 dollars. The average investment per kW of growth in this period was $389/kW in 1992 dollars, or about $420/kW in 1994 dollars. These figures understate avoided distribution costs because:

- The measure of demand includes transmission-level sales not served on distribution, and primary-voltage sales not served through the secondary system. Reducing the demand level to reflect only the loads using the equipment would increase the cost per kW.
- Meter and service costs are affected by demand. Higher demand levels result in commercial customers being classified into rate classes that require more expensive meters. Higher loads require larger-capacity services.
- Some retirements are caused by age or accident, but other retirements are caused by load growth: higher loads cause distribution equipment (especially underground lines and transformers) to wear out faster, and load growth results in smaller equipment being removed prematurely to make way for larger equipment. These load-related retirements should not be removed from the additions.

On the other hand, some of the costs included in my estimate may not vary directly with load levels, due to the need to cover a fixed area. Overall, $400/kW seems to be about the right value for avoided distribution costs,

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of 18 years at a 4% inflation rate. The dollar-weighted average life of the plant retired in any year is less than the average life of any year's cohort of plant, because (a) inflation causes the more recent equipment to be more expensive than the old equipment, and (b) load growth results in there being more recent equipment than old equipment on the system.

subject to small adjustments. This value is about eight times as large as FPL's estimate.

b) Understatement of Avoided Transmission Costs

Q: Is the $100/kW that FPL used in this docket a reasonable estimate of its avoided transmission costs?

A: No. FPL previously estimated an avoided transmission cost of $250/kW in late-1980s dollars. This estimate was the sum of $50/kW for "site-specific" costs and $200/kW for regional costs

> developed by comparing 5 years of projected transmission expenditures (w/o 500kV projects) and comparing this to projections of 5 years load growth. *(Evolution,* p. 3)

While excluding the 500 kV projects may have understated the costs of meeting load growth, this method seems generally reasonable. In Docket No. 920520-EQ, FPL reported that its avoided transmission investment was $253/kW (response to LEAF Interrogatory No. 4).

Q: What was FPL's basis for decreasing its estimate of avoided transmission costs from $250/kW to $100/kW?

A: The *Evolution* reports that a 1992 study of one very small area indicated that the avoided transmission capital costs would be $18–$118/kW over an unspecified period.[52] No detail on the 1992 study has been provided, and the study ~~are~~ area does not appear to be representative of the system as a whole.

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[52]The study area appears to include one proposed reconductoring of an existing 138-kV transmission power line~~s~~, but apparently no proposed new transmission lines or transmission substations.

Including inflation in the \$250/kW value from the late 1980s to 1994, FPL has reduced its estimate of avoided transmission capital cost by about 67%.

Q: Have you attempted to independently estimate avoided transmission costs for FPL?

A: As shown in Exhibit ____ (LEAF-PC-4), the resulting marginal capital costs are \$138/kW from the regression analysis (which does not fit particularly well) and \$180/kW for the average investment per kW, both in 1992 dollars, or \$150–\$194/kW in 1994 dollars.

c) Exclusions

Q: What T&D costs identified in FPL's analysis have been excluded from DSM screening?

A: As discussed above, FPL ignored all customer-owned distribution plant, the customer contributions to FPL-owned plant, all secondary lines, transformers and primary laterals, and other load-related costs. All of these exclusions are reflected in the combined T&D capital value of \$150/kW applied for some measures for some customers. Even this small value is not applied to DSM for larger C/I customers, and to some residential and GS measures that FPL acknowledges reduce peak loads.

Q: What is FPL's rationale for giving no T&D credits to measures affecting its larger customers?

A: FPL's stated rationale is:

> ...FPL specifically assigns "regional transmission [and distribution]" benefits to a variety of DSM programs/measures. These generic "regional transmission" avoided costs are assigned to DSM programs/measures that have the potential for a wide geographic dispersion across FPL's service territory. Consequently, these programs/measures have the potential to "impact" FPL's regional transmission grid at many points." (IR LEAF 1-16, 17)

FPL asserts that for large customers, "the impact of these programs/measures is not as widely distributed across FPL's system" (IR LEAF 1-16, 17) and that

> The commercial DSM program has a lesser impact on T&D than the residential program because the commercial customers and in localized areas, whereas the residential customers are distributed across the system. Thus, the commercial program would positively affect a small area, whereas the residential program would benefit the entire system. Furthermore, the FPL system is largely residential based. (Evolution, p. 4)

Q: Is this a valid justification?

A: No. The rationale simply makes no sense. Whether evenly distributed over the service territory or concentrated in one location, reducing commercial air-conditioning load will reduce the strain on the distribution system, and as a result reduce costs. In fact, the explanation is backwards: if anything, concentrated savings are more likely to avoid the need for T&D expansions. Since FPL has included only the costs of transmission, substations, and major feeders (which serve thousands of customers), it is not clear why FPL believes that these avoided costs would be significantly different for different sizes of customer.[53] The documents provided in Document Request #36 (including "Planning and Reliability: Distribution System Improvements" and "Request

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[53]The distribution study computes the same avoided costs for substations and feeders for all classes.

for Budgeting: Major Construction Project") describe distribution improvements as being required by the total load (including large C/I loads, as on the Crane third feeder) in a localized area.

FPL has not actually determined that the loads of larger C/I customers have no effect on T&D costs. Rather

> FPL retains the option of considering site-specific transmission [and distribution] impacts for these programs/measures on a case-by-case basis. (IR LEAF 1-16,17)

FPL has not included any site-specific impacts in screening, and may have thus rejected measures that would be cost-effective, even under FPL's own understated avoided costs and FPL's preferred RIM test.

Q: What is your basis for stating that FPL does not apply any avoided T&D costs to some residential and GS measures?

A: It appears from Appendix K that (contrary to FPL's response to IR LEAF 1-16 and 17) some residential and GS DSM measures received no T&D credits. For example, measure SCD-4 (FPL program P26) , a residential high-efficiency room air conditioner measure, receives no T&D credits, even though FPL reports that this "program" reduces peak demand.

Q: Why does FPL exclude T&D benefits for this measure?

A: FPL has provided no explanation on this point, other than the incorrect statements in IR LEAF 1-16 and 1-17.

d) T&D Credit for load management

Q: What T&D credit does FPL apply to load-management measures?

A: Load management receives 60% of the distribution credit that conservation receives (IR LEAF 1-17(b)). This value is based on an analysis, in the distribution study described above, of the correlation between substation peaks and system peaks.

Q: Does that analysis appear reasonable to you?

A: No. The analysis fails to recognize that

- Feeder loads may be more diverse (and hence less coincident with system peak) than substation loads.
- Load management measures are operated to maintain generation system reliability, and hence may be used at times different than the system peak (and may thus not be available or needed at peak load).[54]
- If the distribution equipment peaks after the system peaks (or experiences its maximum reliability requirement), the recovery of the controlled equipment may increase load at the distribution equipment peak.

Hence, FPL's estimate of avoided distribution costs for load management is likely to be overstated, at least compared to the estimate of avoided distribution costs for energy efficiency.

3. Losses

Q: What loss factors has FPL used in its avoided cost analysis?

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[54]For example, a major power plant or transmission line may be lost at 3 p.m. on a high-load day, requiring operation of load management for two or three hours until the supply is returned to service or other supplies are ramped up. The system peak at 5 p.m. may be met without the load management. Depending on the type of load control, further control may not be possible: the contract control limits may have been reached, or the recovery from the earlier disconnections may increase load at the peak hour. Hence, load management operated for bulk supply reliability may not reduce peak distribution loads, even if those coincide with the system peak.

A: FPL applies a demand loss factor of 10.58% and an average energy loss factor of 7.87% (IR LEAF 1-12(h)(1)).

Q: Are these values appropriate for screening DSM?

A: No. The demand loss factor assumed is reasonable but the energy loss factor will result in the under-estimate of avoided costs for the following reasons:

- FPL incorrectly applies average line losses, rather than marginal losses;
- FPL's analysis fails to recognize that marginal losses vary between and within rating periods, as load level varies.

4. *Risk-Mitigating Advantages of DSM*

Q: Does FPL reflect the risk-mitigating advantages of DSM in its avoided cost estimates?

A: No. Such advantages are not considered. According to its response to IR LEAF 1-32, FPL assumed "most likely" fuel prices in its integration runs and presumably also in its avoided cost estimates and therefore ignored the supply planning and operating risks that fuel price volatility imposes and DSM can avoid.

D. Achievable potential

Q: In addition to the problems you have identified in STEPS I and IV of the analysis, are there also problems with STEPS II and III of FPL's four-step screening process?

A: Yes. FPL's determination of the achievable potential of measures forwarded to integration has the following problems:

- FPL based its estimates of adoption probabilities on payback-acceptance and diffusion curves, which tend to understate potential participation.
- FPL's method of determining the achievable market size for competing measures under-estimates achievable potential.
- It appears that the measures excluded from FPL's DSM portfolios nevertheless affect ~~the~~ FPL's projection of the achievable potential of measures forwarded to packaging and integration.
- FPL inappropriately reduced achievable potential by limiting incentive levels based on a two-year payback rule.

Q: Why are payback-acceptance and diffusion curves an unreliable basis for estimating participation?

A: FPL's methodology fails to recognize that participation depends upon the quality of program design. Payback-acceptance and diffusion curves reflect such market barriers as limited access to capital, institutional impediments, split incentives (e.g., between landlord and tenant), information costs, risk perception, and inconvenience, which 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 by designing programs to reduce or eliminate these barriers.

In addition, properly structured DSM programs can affect participation by transforming the market. For example, utility programs can

- change the status of efficient equipment from expensive special-order items to standard stock.

- Change the standard practices of engineers, architects, contractors, and plumbers, through education, demonstration, development of support (e.g., analytical services, equipment availability), and reduction of risk.
- Get a broader range of efficient equipment into stores and onto distributor's shelves.
- Create customer demand for higher efficiency equipment, and greater awareness of the range of alternatives.

Q: How does FPL compute the achievable market size of competing measures?

A: FPL assumes that the adoption probability of the standard (non-DSM) option is 100% minus the maximum adoption probability of the competing conservation options. It allocates ~~the remainder of~~ the eligible market among the ~~DSM~~ all options (in proportion to adoption probability). ~~so that no matter how many competing DSM options and no matter what their cost-effectiveness, DSM's overall share of the eligible market will not exceed the individual adoption probability of the most acceptable option.~~

Q: What's wrong with FPL's formula for determining adoption probabilities?

A: First, FPL's formula ignores the Company's ability to affect participant choices through good program design. For example, consider two competing DSM measures with the same payback and the same adoption probability of 50%, but with different measure savings. FPL would assign equal adoption probabilities of 25% to the two measures, when, in reality, good program design would discourage or prevent the less effective measure from displacing the more effective measure.

Second, the first step of FPL's formula implicitly treats the potential market for one DSM measure ~~to be~~ as a simple subset of the group of customers that would accept the measure with the next-highest probability of adoption. As a result, FPL is likely to understate the achievable market for DSM. As an example, consider two measures A and B, each with an adoption probability of 50%. FPL would assume the worst case: the same set of customers constitute both potential markets. It is more likely that the potential markets for the two measures are not the same. It could be, for example, that for each measure, half of its market consists of customers that would adopt one of the measures but not the other and the other half consists of customers who are indifferent between the two DSM measures. If so, the achievable market for DSM is 75% of the eligible market, not the ~~50~~67% share that FPL's formula would indicate.

Q: Why do you believe that measures excluded from the DSM portfolio affected the adoption probabilities and measure interactions assumed for measures forwarded to integration?

A: FPL estimated adoption probabilities and measure interaction effects *before* the second measure screening. There is no indication that FPL recalculated adoption probabilities and adjustments for measure interactions after the final screening to remove the effects of rejected measures. As a result, the estimates of achievable potential could inappropriately reflect the influence of (1) measures rejected in second screening but passed in the first, (2) CUE measures, and (3) measures rejected in the first screening but mistakenly passed on to the second screening, as discussed above.

Q: How are CUE measures treated in FPL's achievable potential analysis?

A: The treatment of CUE measures in FPL's development of adoption probabilities and measure interactions is completely undocumented. FPL provides only the unsupported assurance that its proposed goals reflect "proper consideration" of CUE measures (Hugues, p. 11). FPL has not explained whether and to what extent FPL included interactions between CUE measures (as competing and complementary measures) and UP measures, reducing the savings and adoption rates for the latter, and hence reduced the projection of achievable potential for utility program measures.

E. Resource Integration and Goal-Setting

Q: Briefly summarize the integration phase of FPL's resource planning.

A: At this stage of the planning process, FPL planned the implementation of each option using an algorithm that attempted to minimize costs (in the case of the TRC portfolio) and minimize RIM impacts (in the case of the RIM portfolio) subject to constraints. Based on the outcome of this "packaging," FPL then developed three competing resource plans, a Supply-Only plan, a RIM Portfolio Resource Plan and a TRC Portfolio Resource Plan, and used the EGEAS model to compute average rates and present value revenue requirements (PVRR) for each of the three resource plans.

Q: What problems have you identified with the packaging and integration phase of FPL's analysis?

A: I have identified the following problems with FPL's packaging and integration analysis:

- In its packaging analysis, FPL fails to distinguish lost opportunities from retrofits ~~in its packaging analysis~~.
- FPL inappropriately omits CUE measures from resource planning.
- There is no demonstration that the supply additions in the "supply-only" case or in the DSM cases are least-cost resources.

Q: Why should the packaging process distinguish lost opportunities from retrofits?

A: Seeking simply to minimize costs under constraints without regard to lost opportunities will result in implementing DSM that could have been deferred while foregoing DSM that will be lost forever.

Q: Should the Commission consider utility demand-side-management measures which qualify for inclusion in the building code in setting goals?

A: Yes. Not all measures that could be covered by code are covered; indeed, some cost-effective low-load-factor measures may not be cost-effective (without a utility program) under the participants' test that is used in screening options for inclusion in the code. Not all measures covered in the code are required in all cost-effective installations. Other measures are included in the code as options for demonstrating compliance. A well-designed new-construction program will result in construction of cost-effective buildings that exceed code requirements, saving money for ratepayers and the state of Florida.

Inclusion of specific future measures in the prescriptive building code is speculative. Utility involvement with the building industry can help drive the building industry (and the building code) to improve energy efficiency, by demonstrating the practicality of additional measures or better designs. The secretary of the Department of Community Affairs, Linda Shelly, correctly noted, "Ground has been lost in developing new options for energy efficiency due to over-reliance upon regulatory standards, i.e. the code has become both a minimum and a maximum goal that builders aspire to meet" (Letter to Chairman Deason, January 13, 1994, p. 3). As measures are added to the prescriptive code, the utilities can ask the Commission to reevaluate DSM programs.

Q: Should utilities' DSM programs and DSM goals include measures that are optional under the current building code?

A: Yes. Builders can comply with the code in many ways, most of which will use only a subset of the cost-effective efficiency options. A well-designed new-construction program will result in construction of cost-effective buildings that exceed code requirements by using more of the specified options, as well as tailoring options to work together and improving design.

Q: How has FPL failed to demonstrate that the supply additions in the three competing resource plans are least-cost resources?

A: First, the coal units in the resource plans were not selected as the optimal supply choice. Instead, the coal units serve simply as place holders for the "to be determined" capacity in the resource plan.

In addition, FPL understates the cost of "supply-only" plan by accepting a 42 MW "shortage." FPL suggests that the 42-MW deficiency for one year is of minor importance on a 1600-plus MW system. As long as FPL has the obligation to meet its reliability constraints, this small deficiency could make a substantial difference to the PVRR savings of DSM, for two reasons. First, while the 42 MW is small portion of total needs, it is a much larger portion of the annual increment. Second, because of the lumpiness of generating capacity additions, FPL will probably have to put in a much larger than 42 MW unit to meet 42 MW supply deficiency.

Finally, for some reason FPL takes the position that the capacity needs in any given year must be met entirely with one resource or the other, not with a mix of supply and demand-side resources. In any one year, the FPL system may require more than one CT or CC unit or supply additions of different types, but FPL's resource planning does not permit the mixing of

DSM and supply resources. As a result, in the planning period FPL decides that it can use only 940 MW of the 1,150-MW RIM potential, because the increment of capacity need in 2002 exceeds the remaining 210 MW of RIM potential (CEGRR, p. 71). For purposes of its goal-setting, therefore, FPL essentially treats this 210 MW of DSM as worthless.

Q: How did FPL use the results of screening and integration analysis to set goals?

A: FPL set its goals at the achievable potential of the RIM portfolio.

Q: What is wrong with FPL's selection of the RIM portfolio?

A: FPL's justification for its selection of the RIM portfolio is not valid for at least two reasons. First, the RIM portfolio does not maximize benefits for ratepayers. Second, FPL's analysis of environmental effects is flawed.

1. Reliance on the RIM Test

Q: What is FPL's basis for its reliance on the RIM test?

A: FPL selects the resource plan that minimizes levelized average rates, not the net present value of total costs. FPL does claim that it regards DSM as a tool to lower both prices and bills (Hugues, p. 65). However, in choosing the RIM portfolio over the TRC portfolio, it finds that a reduction of 0.06 cents in average rates is worth the additional utility costs of $550 million (CEGRR, p. 80). In an attempt to magnify the rate impact of the TRC portfolio, FPL calculates that FPL would have to increase its revenue requirements by $500 million in 1994 or by $1.8 billion in 2006 to bring the levelized average rate under the RIM portfolio to the level under the TRC portfolio resource plan (CEGRR, p. 78).

In addition, FPL (Hugues, p. 14) contends that the higher achievable potential of the TRC portfolio is unnecessary:

> There is no apparent need to choose an alternative DSM course that would raise rates to avoid capacity in the ninth and tenth year of the analysis. FPL would not commit to a supply option so far in advance.

Finally, FPL takes the position that DSM past 2001 is unlikely to be cost-effective because the benefits are discounted back 8 years (CEGRR, p. 92)

Q: Are FPL's calculations of the "cost" of the TRC portfolio valid?

A: No. FPL's calculations are completely misleading. FPL essentially equates the lowest-cost TRC Portfolio Resource Plan with the higher cost RIM Resource Plan *plus* a completely wasted expenditure of $500 million (in 1994). Thereby, FPL implies that the costs of the TRC resource plan are actually $1,050 million higher than the plan's PVRR.

FPL again treats a rate re-design as though it were a cost, confusing RIM distribution effects with resource costs.[55]

Q: Are FPL's other justifications for its selection of the RIM portfolio valid?

A: No. First, the inclusion of DSM past 2001 in the resource plan is no more a commitment to the resource than is the inclusion of supply resources.

Second, if the DSM is economic after 2001, discounting will not affect its cost-effectiveness, because the costs as well as the benefits are discounted.

Q: Are the rate impacts of the TRC portfolio excessive?

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[55]FPL has confused RIM effects with costs in the past.

A: They do not appear to be. In fact, the TRC resource plan also reduces levelized average rates below that of the Supply-Only plan, and therefore passes FPL's RIM test.

2. *Environmental Effects of DSM Resource*

Q: What are the results of FPL's analysis of the environmental effects of DSM?

A: FPL computes annual oil burn, SO_2 emissions, NOx emissions, and CO_2 emissions for the supply-only base case, FPL's RIM portfolio, and FPL's TRC portfolio. For CO_2, FPL reports that the TRC portfolio is always lower than the RIM portfolio, which is always lower than the Base Case. From 1995 through 2000, the same is true for oil burn, SO_2 emissions, and NOx emissions. By 2003, when DSM would be avoiding coal units, FPL reports that the Base Case results in the lowest value for these three measures, with the RIM higher, and the TRC Case highest. Hence, FPL concludes that the cleanest energy resource (DSM) is actually the dirtiest.[56]

Q: Is this a reasonable conclusion?

A: No. This counter-intuitive result followed almost automatically from the fact that FPL assumed that DSM with a relatively low load factor would back out combined-cycle and (more importantly) coal plants with high capacity factors. Thus, a small amount of clean DSM energy replaces a much larger amount of slightly-dirty new supply, resulting in increased use of the very dirty existing units.[57] The problems with this assumption include:

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[56]Dr. Sim does not provide any documentation supporting his summary results. My earlier cautions regarding undocumented FPL assertions apply here.

[57]Recall that FPL does not include the costs of complying with environmental regulations, as I discussed above. FPL may also overstate the emissions of the existing units in this analysis,

- FPL did not match DSM with the avoided supply. If the DSM avoided a mix of supply with a similar aggregate load factor, the TRC case would continue to be the low-emission case for NOx; after 2002, SO_2 and oil results would be similar for all cases.
- FPL appears to back out more baseload plant than can be justified by the demand savings reported for the DSM. This exaggerates the environmental effect, and may understate the economic benefits of the DSM (assuming the baseload plant was cost-effective in the first place).
- It is not clear why FPL adds only baseload plants in the Base Case. FPL has not demonstrated (or apparently even claimed) that the Base Case is the optimal least-cost choice. Indeed, coal plants are simply assumed to be the "to be determined" capacity in the supply plan.[58]
- If FPL added a least-cost mix of coal, combined-cycle, and CTs in the base case, and avoided a least-cost mix of units with DSM, both the direct costs and the environmental effects of the three cases would be more realistically represented.
- If adding entirely baseload plants in the Base Case is actually cost-effective, avoiding them in the DSM cases is probably not cost-effective. Instead, the least-cost plan with DSM might include construction of some of the baseload plants, and sale of peaking capacity (matching the DSM load shape) off-system.

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by ignoring the installation of low-NOx burners (including over-fired air technology), gas use in dual-fuel plants, reduction of oil sulfur content, and scrubbing at Manatee.

[58]Overstating the amount of baseload capacity added to FPL's system will understate FPL's avoided fuel costs and, since FPL's avoided cost does not allow the avoidance of the baseload units, will understate FPL's total avoided costs.

V. Recommended Goals

A. Relationship between Proposed Goals and Estimates of Potential

Q: How do the utilities' goals relate to their estimates of achievable potential under the TRC and RIM tests, and to SRC's estimate of cost-effective potential under the TRC test?

A: Exhibit ____ (LEAF-PC-5) shows the following information for each utility, for 2003:

- SRC's estimate of achievable potential that would be cost-effective under the TRC, with best practices in program design;
- An adjustment to the SRC achievable potential for the measures that the Commission removed from the mandatory analysis (that is, those that are neither UP nor CUE);
- The utility's own estimate of its achievable potential that would be cost-effective under the TRC test;
- The utility's own estimate of its achievable potential that would be cost-effective under the RIM test; and
- the utility's proposed goals.

Q: Why do you start with SRC's estimated achievable potential for the TRC test and the best-practices program design?

A: As explained above, the TRC is the test that minimizes total cost and is consistent with the public interest. I used the best practices (BP) case because it is SRC's most realistic attempt to model cost-effective DSM potential. For the SRC analyses, conducted in 1992, the BP standard would have been based on programs in place in 1990 or 1991, which are already three or four years old, and will be nearing a decade old by the middle of the ten-year goals period. Well-designed DSM programs implemented in the period 1994-2003 are likely to exceed the BP adoption projections.[59] The utilities considered in this testimony are all large enough and sophisticated enough to match the best practices of other utilities, given a lag of 4–13 years.

In addition, the other SRC assessments of cost-effective potential are based an unrealistically high 10% real discount rate. The 5% real discount rate used in the BP scenario is very close to the real discount rates used by the utilities in these proceedings.

Q: How did you make the adjustment for the Commission's treatment of measures?

A: While the Commission did not prohibit the inclusion of the "Code", "Behavioral", or "R&D" measures in goals, the Commission's Fourth Procedural Order at least suggests a reluctance to require their inclusion.

For FPL, I listed the cost-effective BP measures that were excluded by the Commission, as shown in Exhibit ____ (LEAF-PC-5), page 6, along with the savings SRC estimated for the measures in 2000 and 2010. I interpolated the savings for each measure in 2003, and totaled the 2003 exclusions. I subtracted the PSC exclusions from the SRC savings, to derive adjusted SRC savings values for 2003.

For the other utilities, I assumed the same ratio of PSC exclusions to SRC-BP savings as for FPL. Since the excluded measures represent only 6–7% of demand savings and 9% of energy savings, this approximation should not significantly affect my results.

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[59]This is particularly true on a savings-weighted basis, since SRC did not assume that programs made any attempt to direct participants to the measures with the greatest net benefits.

Q: How do the utilities' estimates of TRC potential compare to the adjusted SRC estimates?

A: There is a wide variation in the ratio of utility estimates of TRC potential to the adjusted SRC estimates. Since energy requirements drive most utility costs (fuel, variable O&M, the higher fixed costs of intermediate and baseload plants, and most environmental compliance costs), I will describe the energy results here. The demand results are shown in the Exhibits. In increasing order,

- FPL and Gulf report TRC potential that is only 31% of the adjusted SRC estimate,
- TECo reports 101%, essentially the same potential found by SRC, and
- FPC reports 172%, considerably more cost-effective potential than the SRC BP case.

Q: How do the utilities' estimates of their RIM potential compare to their own estimates of TRC potential?

A: Except for Gulf, there is a negative correlation between the SRC:utility-TRC ratio and the utility RIM:TRC ratio. FPL reports RIM potential that is 63% of its low TRC potential estimate, TECo reports RIM potential that is 48% of its moderate TRC potential estimate, and FPC reports RIM potential that is 26% of its higher TRC potential estimate. Gulf reports RIM potential of only 29% of its low TRC estimate.

Q: How do the utilities' proposed goals compare to the potential estimates?

A: Each of the utilities proposes goals that are less than even their own estimates of RIM potential, even though the goal proposals are based on the RIM-potential estimates. TECo's goal:RIM ratio was 47%; the ratios of the other utilities ranged 63%–72%.

The proposed goals, as a percentage of adjusted SRC best-practice TRC potential, are spread over a wide range. At the low end, Gulf and FPL propose goals of 6% and 12% of adjusted SRC potential, respectively, while TECo and FPC propose goals of 23% and 32% of potential.

Q: What accounts for the differences between the various estimates of potential and goals, within and between utilities?

A: Some of these differences are easily explained. For example, Gulf requests that its goals should be set at 70% of its RIM-potential estimate, based on an argument that its RIM potential is based on "engineering estimates."[60] TECo excludes from its goals all measures (other than those that are in TECo's existing DSM programs) that pass the RIM test with a cost-effectiveness ratio of less than 1.2.

Other differences may result from a range of problems, including those I described above for FPL, such as:

- Setting incentives at low levels, based on the RIM test, arbitrary payback criteria (e.g., FPL), or the use of the SRC "moderate marketing/low incentive" scenario to determine achievable potential (e.g., TECo).
- FPL's termination of its RIM portfolio in 2000.
- Assumption that program design would reflect moderate marketing, not best practices.
- The use of low avoided costs.
- Inappropriate modeling of the interaction of competing measures.

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[60]Gulf does not provide any documentation for this position; I would be very disappointed to find that the SRC savings estimates are based solely on engineering estimates, given the experience with actual savings available to date.

- Inappropriate inclusion of rejected measures in estimating the savings and adoption of measures still under consideration.
- Arbitrary rejection of measures, including those with paybacks of less than 2 years, and of CUE measures.[61]

I have not attempted to determine what part of the differences result from each of these and other problems.

B. Use of the RIM Portfolio In Setting Goals

Q: Did the utilities act appropriately in deciding to use their RIM portfolios as the basis of their proposed goals?

A: No. A RIM portfolio does not maximize benefits for ratepayers or for the state. A properly constructed TRC portfolio would maximize DSM benefits, minimize revenue requirements, minimize costs of energy service, increase the attractiveness of the state to business, and reduce the cost of living. Utility DSM programs should be designed to maximize TRC benefits, subject to constraints of realistic program ramp-up rates (utilities cannot simultaneously implement all potential programs and do a good job of it) and rate impacts.

Q: Are the rate and bill effects of the TRC-maximizing portfolio likely to be acceptable?

A: Yes. This has been the experience of most utilities. FPL estimates such small rate effects that its TRC portfolio would pass the RIM test.

The rate effects estimated in the FPC CEGRR are over-stated, because they use deferral avoided costs (rather than revenue requirements) and

[61]TECo asserts that "free ridership and RIM risks eliminated the potential" of the cost-effective CUE measures in the goals-setting process (Currier, pp. 14–15), but does not describe or quantify these "risks" or demonstrate that they eliminate anything.

include the deferral of a non-least-cost set of units. FPC shows lower revenue requirements with its TRC portfolio (which is much larger than the adjusted SRC best-practices TRC portfolio) than with the Base Plan for each year from 1998 onward.[62]

C. LEAF Proposed Goals

Q: What should be the basis for the utilities DSM goals?

A: The energy goals should be no lower than the SRC Best Practice achievable potential that is cost-effective under the TRC, adjusted for PSC exclusions. I therefore recommend that the energy goals for 2003 be set at the adjusted SRC values shown in Exhibit ____ (LEAF-PC-5). Given the results of FPC's TRC analysis, this goal seems rather modest, but we have no other basis for setting specific goals for the other utilities.

Q: What energy goals do you suggest for 1995–2002 and 2004?

A: I suggest spreading the sales over time in the pattern used in the utilities' TRC portfolio, with an adjustment for lower savings in the early years, to

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[62]TECo has filed a table that shows higher revenue requirements for the TRC case than for the RIM or base case, for each year 1995-2004 (Deposition Exhibit No. 2). The company provided no supporting documentation, so I cannot review its analysis in detail. However, the assertion in the table that the TRC portfolio could increase revenue requirements by $130 million over the base case (for a utility with only $282 million in base revenues) is almost certain to be a computational error. Even the most aggressive of utilities have been spending less than 10% of their revenues on DSM, much of which is offset by avoided utility costs, so TECo's revenue increase is overstated by roughly an order of magnitude. Even if TECo's computational error (whatever it is) were corrected, TECo might project that a reasonable TRC portfolio would increase revenue requirements in the early years of the plan, especially if TECo failed to credit DSM with avoiding T&D costs and allowing for additional off-system sales of TECo's excess capacity and its cheap coal-fired energy.

allow for program start-up. Exhibit ____ (LEAF-PC-6) shows the results of my extrapolation of my proposed 2003 goals to the other years.[63] These goals are cumulative savings, starting with 1995 installations, the first that could be affected by the order in this proceeding; any energy savings achieved from 1994 installations should be added to these goals.

Q: Are these demanding levels to meet?

A: No. The SRC Best Practice Scenario understates achievable potential in several ways:

- The avoided costs were provided by the utilities, and appear to be understated.
- SRC did not include externalities.
- SRC did not consider fuel-switching measures.
- DSM program design and efficiency technologies are likely to be better in the period 1994–1995 than was the case in the 1990–91 period on which SRC could base its assessment of "best practice" and technology.
- SRC assumes that the program design will not place any priority (either in recommendations or in incentives) on the competing measures that would maximize benefits, but splits each market among all options without preference for the best choices.
- SRC screens only for average conditions, which ignores all the options that are cost-effective in favorable conditions (high use, low installation cost), but not in average conditions.

[63] Since the utilities (except for TECo) did not compute portfolios for 2004, I extrapolated savings.

- In screening and in determining achievable potential, SRC assumes that the savings from each previously adopted measure are spread evenly over all customers, even if the measure is adopted only by a small percentage of customers. Again, only average conditions are screened, and SRC ignores the measures that would be cost-effective if applied to the customers who did not adopt the previous measures.
- SRC assumes that savings from one "complementary" measure reduce savings from all subsequent measures. In fact, many of SRC's "complementary" measures operate independently (low-flow showerheads reduce water use while tank wraps reduce standby losses; wall insulation and ceiling insulation reduce heat transfer through different parts of the house), so their savings are additive, or very nearly so.
- SRC "stacks" measures in order of cents-per-kWh costs, and evaluates interactions in order of the stack. SRC does not adjust savings or adoption rates of cost-effective measures later in the stack if measures earlier in the stack fail the avoided-cost screen.[64]

The adjusted SRC case that I used in proposing these goals is even less demanding, since it includes none of the measures the Commission classified as code, behavioral, or research and development. All of these measures could be included in the utility DSM portfolios. Indeed, today's R&D

[64]While the measures early in the stack will tend to be cost-effective more often than measures late in the stack, cost-effectiveness is not perfectly correlated with cents-per-kWh costs, because (1) the cents-per-kWh costs do not reflect interactions, (2) short-lived measures are not worth as much as long-lived measures, and (3) high–load-factor measures are not as valuable per kWh as low–load-factor measures.

measures are likely to be tomorrow's standard practice. In addition, the adjusted SRC case does not remove the interactions that SRC assumed between the PSC-eliminated measures and other options, and hence understates the potential for conservation from the UP and CUE measures.

The goals I have proposed are less ambitious than the goals of leading utilities in DSM implementation nationally.

Q: What goals would you propose for demand savings?

A: Demand savings are less important than energy savings, and harder to verify, so I have concentrated on the energy-saving goals in this analysis. I recommend that the Commission set demand goals that are much less exacting than the energy goals, so that the utilities focus their attention on achieving energy savings and on minimizing total costs. To this end, I recommend setting demand goals at the average of the adjusted SRC portfolio and the utility's TRC portfolio.

Q: Do the utilities propose separate goals for the new construction and retrofit market segments?

A: No.

Q: Should the Commission set separate numerical goals for each class, market segment and end use?

A: Separate goals by class should not be necessary, unless the utilities are reluctant to implement comprehensive programs in each class. In that case, to assure proper program diversity, the Commission should set separate goals for each class. Additional detailed goals may distract the utilities from their primary responsibility of reducing costs to their customers and to the state, and may distract the Commission from enforcing that responsibility.

The Commission should set goals for specific customer-driven market segments in each class, including new construction, industrial process change, and equipment replacement, to ensure that the utilities do not neglect the development of programs to capture these lost opportunities.

In addition, the Commission should set specific goals that require utilities to develop programs for specific types of customers (e.g. low-income residential customers); and specific resources, such as solar energy and natural gas substitution, that the utilities have failed to pursue.

Q: Do you have proposals for these segment-and resource-specific goals?

A: No. I do not have enough information to make these recommendations. I recommend that the Commission establish a schedule for review these issues in a timely fashion, to allow for revision of utility goals within the next year.

VI. Conclusions

Q: Please summarize your conclusions.

A: In order to maximize benefits for customers and the state's economy, integrated resource planning must include several features that the utilities have generally neglected. Major features include:

- the inclusion of all avoidable costs in evaluating DSM;
- the screening of measures and programs, recognizing the appropriate set of costs and benefits at each step;
- the use of Total Resource Cost as the objective in screening, program design, and integration;

- the design of programs to overcome the specific market barriers found in each market segment, and to maximize participation and TRC savings; and
- thoughtful analysis of projected rate and bill effects, identifying any significant equity problems and appropriate cost-minimizing mitigation.

The utilities have not taken all the steps in these dockets that a reasonable IRP process requires. In particular, FPL (among other things):

- rejected cost-effective DSM on the basis of arbitrary and unwarranted rules;
- understated annual avoided costs in several ways;
- understated 1995-2003 program avoided costs, by assuming all installations occurred in 1995;
- overstated measure costs by modeling the full costs of reinstallation of measures but not their full benefits;
- included excessive and arbitrary program overhead costs in the screening of measures;
- understated potential adoption of competing measures;
- set artificially low incentives; and
- screened measures only for average installation characteristics.

Q: Does this conclude your testimony at this time?

A: Yes. I may supplement this testimony as more details become available from FPL.

Qualifications of

PAUL L. CHERNICK

Resource Insight, Inc.
18 Tremont Street, Suite 1000
Boston, Massachusetts 02108

mary of Professional Experience

Pr **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

Research Associate, Analysis and Inference, Inc. (Consultant, 1980–81). Researched, advised, and testified 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.

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"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"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.

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".

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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

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, 1984.

    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 R-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.

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 6, 1990.

Analysis of a proposed 450-MW, 20 year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to 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 Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December, 1989; April, 1990; May, 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. California Public Utilities Commission; Incorporation 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 Counselor; 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 purchases 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 Company; October 4, 1991. Rebuttal December 13, 1991.

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

97. Florida PSC Docket No. 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21, 1991.

    Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. Florida PSC Docket No. 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31, 1991.

    Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. Pennsylvania PUC Dockets I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10, 1992.

    Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. South Carolina PSC Docket No. 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20, 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. Massachusetts DPU Docket No. 92-92; Adequacy of Boston Edison's Streetlighting Options; Town of Lexington; June 22, 1992.

Efficiency and quality of streetlighting options. Boston Edison's treatment of high-quality streetlighting. Corrected rate proposal for the Daylux lamp. Ownership of public streetlighting.

102. South Carolina PSC Docket No. 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4, 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. North Carolina Utilities Commission Docket No. E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29, 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRP's of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. Ontario Environmental Assessment Board–Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning*; October, 1992.

105. Public Utility Commission of Texas Docket No. 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28, 1992.

106. Maine Board of Environmental Protection; In the Matter of the Basin Mills Hydroelectric Project Application; on behalf of Conservation Intervenors; November 16, 1992.

107. Maryland Public Service Commission Case No. 8473; In the Matter of the Application of the Baltimore Gas and Electric Company for the Review and Approval of the Power Sales Agreement Between the Baltimore Gas and Electric Company and AES Northside, Inc.; Maryland Office of People's Counsel; November 16, 1992.

108. North Carolina Utilities Commission Docket No. E-100, Sub 64; In the Matter of Analysis and Investigation of Least Cost Integrated Resource Planning in North

Carolina—1992; Southern Environmental Law Center, on Demand-Side Management Cost Recovery and Incentive Mechanisms; November 18, 1992.

109. South Carolina Public Service Commission Docket No. 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24, 1992.

110. Maryland Public Service Commission Case No. 8487; Application of the Baltimore Gas and Electric Company for an Increase in Electric Rates; January 13, 1993. Rebuttal Testimony: February 4, 1993.

111. Maryland Public Service Commission Case No. 8179; Petition of Potomac Edison for Approval of Amendment No. 2 to the Electric Energy Purchase Agreement with AES Warrior Run, Inc.; Maryland Office of People's Counsel; January 29, 1993.

112. Michigan Public Service Commission Case No. U-10102; In the Matter of the Application of the Detroit Edison Company for Authority to Amend its Rate Schedules Governing the Supply of Electric Energy; Michigan United Conservation Clubs; February 17, 1993.

113. Federal Energy Regulatory Commission Projects Nos. 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

    Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

114. Illinois Commerce Commission 92-0268, Electric-Energy Plan for Commonwealth Edison ; City of Chicago; February 1, 1994.

    Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

Summary of Externality Values.

Exhibit___(LEAF-PLC-2) page 1 of 2

	Calif. PUC SCE&SDGE ($1989)	Calif. PUC PG&E ($1989)	Mass. DPU ($1992)	Minn. PUC (interim) ($1994)	Nevada PSC ($1990)	New York PSC ($1989)	New York SEO ($1992)	Oregon PSC (low) ($1993)	Oregon PSC (high) ($1993)	Wisc. PSC ($1992)	BPA (west) ($1990)	BPA (east) ($1990)
Pollutants	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
SO_2	19,717	4,374	1,700	1,500	1,560	832	921				1,500	1,500
NO_x	26,397	1,904	7,200	760	6,800	1,832	4,510	2,000	5,000		884	69
VOCs	18,855	3,556	5,900	5	1,180		3,188					
TSP/PM10 [13]	5,710	2,564	4,400	1,280	4,180	333	2,645	2,000	4,000		1,539	167
CO			960		920		307					
Air toxics							75,490					
Greenhouse gases												
CO_2	7.6	7.6	24	7.6	22	1.10	6.20	10	40	15		
CH_4			240		220					150		
N_2O			4,400		4,140					2,700		
Site-specific externalities												
Water use (c/kWh)					site-spec.	0.1						
Land use (c/kWh)					site-spec.	0.4					0-0.2	0-0.2

Notes:

[1],[2]:California PUC values from California Energy Commission Staff, "In-state Criteria Pollutant Emission Reduction Values," (Testimony) November 19, 1991, Table 2. CEC values are presented in a separate table.

[3]: Massachusetts DPU Decision in Docket 91-131, November 10, 1992.

[4]: Minnesota PUC Decision in Docket No. E-999/CI-93-583, March 1, 1994.

[5]: Nevada PSC Decision in Docket No. 89-752, January 22, 1991. NOx and VOC values are for ozone non-attainment areas only. NOx value for non-attainment area would be higher, and VOC value would be $5,500/ton.

[6]: NYPSC, "Consideration of Environmental Externalities in New York State Utilities Bidding Programs," 1989. Values are: 0.25 c/kWh for SO2, 0.55 c/kWh for NOx, 0.1 c/kWh for CO2, 0.005 for TSP, 0.1 c/kWh for water discharge, and 0.4 c/kWh for land use impacts for a total of 1.405 c/kWh total for a NSPS coal plant. Values are translated to $/ton by Sury Putta, "Weighing Externalities in New York State," The Electricity Journal, July 1990.

[7]: NYSEO, 1994 Draft New York State Energy Plan, Volume III: Supply Assessments, February 1994, p. 529. Values shown represent "mid-range values. For utility planning, low values were estimated as 50% of mid-range values and high values 200% of mid-range values.

[8],[9]: Oregon PUC Order No. 93-695, May 17, 1993, p. 5.

[10]: Wisconsin PSC Order in Docket No. 05-EP-6, September 18, 1992, p. 95.

[11], [12]: Bonneville Power Administration, "Application of Environmental Cost Adjustments During Resource Cost Effectiveness Determinations," May 15, 1991. -"Land and other" values vary from 0 for DSM to 0.2 c/kWh for coal and new hydro. SO2 value is zero if offsets are purchased.

[13]: Values for Minnesota are per ton of particulate matter smaller than 10 microns (PM10); all other values are per ton of total suspended particulates (TSP).

Blank space indicates that a value for that externality was not estimated.

updated 4/25/94

Summary of Externality Values, Continued: California Energy Commission.

	South Coast [1]	Bay Area [2]	San Diego [3]	San Joaquim Valley [4]	Sacramento Valley [5]	North Coast [6]	North Central Coast [7]	South Central Coast [8]	Southeast Desert [9]	Out of state Northwest [10]	Out of state Southwest [11]
Pollutants											
SO2	7,425	3,482	2,676	1,500	1,500	1,500	1,500	1,500	1,500	1,500	1,500
NOx	14,483	7,345	5,559	6,473	6,089	791	1,959	1,647	439	730	760
ROG (VOC)	406	90	98	3,711	4,129	467	803	286	157	0	5
PM10	47,620	24,398	14,228	3,762	2,178	551	2,867	4,108	715	1,280	1,280
CO	3	1	1	0	0	0	0	0	0		
Greenhouse gases											
CO2	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6	7.6
CH4											
N2O											

Notes:
Source: California Energy Commission Electricity Report, November 1992, Tables 4-1 and 4-2.
[1]: Includes Ventura County.
[1]-[9]: Values for resources located within California.
[10],[11]: Values for resources located outside California.
A blank space indicates that a value for that externality was not estimated.

Florida Power and Light Company Plant Distribution Calculations

	1981-1982	1982-1983	1983-1984	1984-1985	1985-1986	1986-1987	1987-1988	1988-1989	1989-1990	1990-1991	1991-1992
handy whitman index	221	225	227	227	230	230	241	255	263	267	267

Net additions in constant dollars [1]

Distribution Plant	1981-1982	1982-1983	1983-1984 [2]	1984-1985	1985-1986	1986-1987	1987-1988	1988-1989	1989-1990	1990-1991	1991-1992
Land	$515,706	$444,881	($188,707)	$911,657	$798,628	($496,793)	$151,165	$15,770	$265,920	$2,717,000	$1,439,313
Structures	$2,391,576	$1,391,212	$1,307,017	$2,455,379	$3,472,962	$2,562,059	$336,688	$1,731,919	$4,652,070	$4,902,470	$3,201,090
Station Eq	$32,491,454	$16,768,192	$15,477,051	$22,638,033	$23,329,162	$22,719,757	$19,684,657	$45,952,778	$76,366,875	$76,975,823	$64,914,891
Storage	$0	$0	$0	$0	$0	$0	$0	$2	($2)	$0	$0
Poles	$5,204,062	$8,001,499	$19,362,785	$15,056,613	$15,313,726	$17,020,953	$19,166,782	$21,120,902	$21,282,494	$18,140,012	$16,816,137
Overhead	$24,758,556	$19,998,674	$31,350,120	$24,590,250	$15,390,372	$29,338,829	$35,479,577	$45,041,122	$43,593,735	$32,607,204	$23,466,613
Conduit	$18,770,742	$14,155,982	$17,059,390	$18,978,480	$21,031,460	$22,634,631	$25,578,774	$32,422,826	$29,054,930	$23,251,398	$17,497,093
Conductor	$42,610,790	$46,798,825	$55,044,527	$45,784,887	$36,033,247	$30,186,262	$30,799,629	$40,787,760	$47,338,668	$36,820,683	$28,020,058
Line Trans	$27,427,968	$34,484,319	$60,440,636	$48,043,787	$52,940,457	$42,854,217	$48,302,014	$54,978,857	$53,752,736	$44,763,592	$38,422,601
Total	$154,170,852	$142,043,583	$184,864,201	$178,459,086	$168,310,015	$166,819,916	$179,499,286	$242,051,936	$276,307,425	$240,178,182	$193,777,796

Notes: Index source: The Handy-Whitman Index of Public Utility Construction Costs, 1993, Whitman, Requardt and Associates. 1993.
[1] Constant values of net additions were calculated using the Handy-Whitman index for July.
Net additions were calculated by subtracting retirements from the changes in total distribution.
Sources: Financial Statistics of Selected Electric Utilities for years 1981-1992; and Ferc Forms for years 1981-1992, pp. 202-204.
[2] The total net additions for 1983-1984 is the sum of the individual distribution components for that period, minus an estimate of constant dollar total distribution retirements for 1983.
Retirements estimate for 1983 is an average of 1982 and 1984 values. See preliminary calculations table.

Regression data for FP&L's Plant Distribution

Year	Cumulative Changes in load (MW)	Total Annual Changes in Distribution	Cumulative Additions in plant		Regression of Cumulative additions in plant ($s) on Cumulative changes in load					
					m	349,858	b	197,481,811		
1981		$0			se	22,039	se (b)	67,401,241		
1982	155	$154,170,852	$154,170,852		r-sq	0.97	se(y)	129,775,322	Average addition =	
1983	938	$142,043,583	$296,214,436		F	252	df	9	$389	/kW
1984	532	$184,864,201	$481,078,637		SS (reg)	4.24E+18	ss(resid)	1.52E+17		
1985	916	$178,459,086	$659,537,722							
1986	1,284	$168,310,015	$827,847,737							
1987	2,656	$166,819,916	$994,667,653		Regression Calculation					
1988	2,644	$179,499,286	$1,174,166,939		349,858	197,481,811				
1989	3,687	$242,051,936	$1,416,218,875		22,039	67,401,241				
1990	4,270	$276,307,425	$1,692,526,300		0.966	129,775,322				
1991	4,846	$240,178,182	$1,932,704,482		252.006	9.000				
1992	5,464	$193,777,796	$2,126,482,278		4.24E+18	1.52E+17				

Florida Power and Light Company Plant Distribution												
Preliminary calculations												
Net additions in nominal dollars												
	1981-1982	1982-1983	1983-1984	1984-1985	1985-1986	1986-1987	1987-1988	1988-1989	1989-1990	1990-1991	1992-1992	
Land	$426,858	$374,900	($160,436)	$775,079	$687,957	($427,949)	$136,445	$15,061	$261,936	$2,717,000	$1,439,313	
Structures	$1,979,544	$1,172,370	$1,111,209	$2,087,532	$2,991,690	$2,207,017	$303,902	$1,654,080	$4,582,376	$4,902,470	$3,201,090	
Station Eq	$26,893,675	$14,130,499	$13,158,392	$19,246,567	$20,096,282	$19,571,326	$17,767,799	$43,887,485	$75,222,802	$76,975,823	$64,914,891	
Storage	$0	$0	$0	$0	$0	$0	$0	$2	($2)	$0	$0	
Poles	$4,307,482	$6,742,836	$16,461,993	$12,800,941	$13,191,599	$14,662,244	$17,300,354	$20,171,648	$20,963,655	$18,140,012	$16,816,137	
Overhead	$20,493,037	$16,852,815	$26,653,473	$20,906,317	$13,257,624	$25,273,149	$32,024,637	$43,016,802	$42,940,645	$32,607,204	$23,466,613	
Conduit	$15,536,831	$11,929,198	$14,503,676	$16,135,262	$18,116,988	$19,497,997	$23,087,957	$30,965,620	$28,619,650	$23,251,398	$17,497,093	
Conductor	$35,269,605	$39,437,212	$46,798,156	$38,925,728	$31,039,876	$26,003,147	$27,800,414	$38,954,602	$46,629,474	$36,820,683	$28,020,058	
Line Trans	$22,702,550	$29,059,819	$51,385,859	$40,846,216	$45,604,139	$36,915,618	$43,598,447	$52,507,897	$52,947,452	$44,763,592	$38,422,601	

Distribution Plant Additions												
	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
Land	$10,818,365	$11,245,888	$11,636,175	$11,475,739	$12,255,906	$13,012,071	$12,584,539	$12,721,991	$12,748,000	$13,033,000	$15,750,000	$17,200,858
Structures	$16,069,856	$18,068,785	$19,276,933	$20,388,142	$22,478,042	$25,480,983	$27,712,353	$28,051,652	$29,767,000	$34,393,000	$39,361,000	$42,687,592
Station Eq	$248,378,282	$276,515,628	$291,736,888	$304,895,280	$325,511,031	$348,546,271	$370,926,344	$391,603,059	$437,879,000	$516,892,000	$594,213,000	$662,413,967
Storage	$0	$0	$0	$0	$0	$0	$0	$0	$2	$0	$0	$0
Poles	$187,350,388	$193,837,657	$203,877,006	$220,338,999	$237,018,351	$254,890,803	$272,723,959	$292,914,195	$316,178,000	$340,443,000	$362,124,000	$382,274,302
Overhead	$259,639,654	$282,396,758	$302,816,254	$329,469,727	$353,983,728	$371,091,526	$399,798,781	$436,261,926	$484,637,000	$534,415,000	$573,977,000	$603,685,404
Conduit	$121,790,297	$137,397,292	$149,391,695	$163,895,371	$180,172,955	$198,436,718	$218,288,931	$241,882,246	$273,294,000	$302,447,000	$326,240,000	$344,184,397
Conductor	$297,813,796	$334,481,567	$375,253,608	$422,051,764	$463,600,740	$497,594,684	$526,298,530	$557,313,466	$600,389,000	$651,749,000	$694,463,000	$728,443,667
Line Trans	$314,014,386	$340,138,119	$373,788,620	$425,174,479	$468,401,385	$519,235,222	$565,702,864	$616,938,370	$676,698,000	$737,641,000	$789,622,000	$828,792,544
Source: Financial Statistics of Selected Electric Utilities for years 1981-1992. Energy Information Administration, Washington D.C.												

Distribution Plant Retirements												
	1981	1982	1983 [1]	1984	1985	1986	1987	1988	1989	1990	1991	1992
Land	665	15,387		5,088	68,208	417	1,007	10,948	23,064		11,545	1,404,074
Structures	19,385	35,778		2,368	11,251	24,353	35,397	61,268	43,624	65,530	125,502	58,149
Station Eq	1,243,671	1,090,761		1,369,184	2,938,958	2,808,747	2,908,916	2,388,456	3,790,198	345,177	3,286,076	7,603,004
Storage												0
Poles	2,179,787	3,296,513		3,878,411	4,680,853	3,170,912	2,889,882	3,092,157	3,301,345	3,540,988	3,334,165	3,199,715
Overhead	2,264,067	3,566,681		3,607,684	3,850,174	3,434,106	4,438,508	5,358,272	6,837,355	6,954,796	6,241,791	6,141,297
Conduit	70,164	65,205		142,322	146,775	354,216	505,358	446,134	533,350	541,602	447,304	436,590
Conductor	1,398,166	1,334,829		2,623,248	2,954,068	2,700,699	3,214,522	4,120,932	4,730,526	5,893,317	5,960,609	6,585,444
Line Trans	3,421,183	4,590,682		2,380,690	5,229,698	9,552,024	7,637,059	7,251,733	7,995,548	7,217,408	747,943	17,711,319
Total	9,333,367	12,853,910	12,743,133	12,632,355	16,861,568	19,211,957	18,685,329	20,269,228	23,398,124	24,148,111	16,731,812	34,074,365
Source: FERC forms for 1981-1992												
Notes: [1] Retirements for 1983 is the average of 1982 and 1984 total retirements												

Florida Power & Light
Transmission Data

	1981	1982	1983 [1]	1984	1985	1986	1987	1988	1989	1990	1991	1992
Handy-Whitman index [2]	216	224	231	231	230	234	233	262	273	284	289	285
Trans. Additions ($)	37,825,549	73,743,270		287,293,586	84,857,668	39,716,843	55,246,669	93,715,558	53,372,597	63,391,835	60,163,358	75,226,196
Retirements ($)	4,160,027	1,591,245		4,956,237	2,721,559	4,253,932	2,435,880	5,245,313	4,543,406	8,258,230	4,136,801	5,898,617
Net Additions ($) [3]	29,505,495	70,560,780	45,393,187	277,381,112	79,414,550	31,208,979	50,374,909	83,224,932	44,285,785	46,875,375	51,889,756	63,428,962
Net Additions in Constant Dollars	38,930,861	89,775,992	56,004,581	342,223,450	98,404,986	38,010,936	61,617,378	90,530,937	46,232,413	47,040,429	51,171,559	63,428,962
Cumulative Changes in Additions		89,775,992	145,780,574	488,004,024	586,409,010	624,419,945	686,037,323	776,568,261	822,800,674	869,841,103	921,012,662	984,441,624
Total Demand for Summer Peak (MW) [4]	9,738	9,893	10,676	10,270	10,654	11,022	12,394	12,382	13,425	14,008	14,584	15,202
Cumulative Changes in load		155	938	532	916	1,284	2,656	2,644	3,687	4,270	4,846	5,464

Notes:

[1] Net Additions for 1983 is the change in total transmission plant for the period 1982-1983, minus the average of 1982 and 1984 retirement values. Total Plant Transmission for 1982 = $866,709,692; Transmission for 1983 = $915,376,620

Source: Financial Statistics of Selected Electric Utilities (1982 and 1983). Energy Information Administration, Washington D.C.

[2] Base year is 1992. Source: The Handy-Whitman Index of Public Utility Construction Costs, 1993, Whitman, Requardt and Associates. 1993.

[3] For all years excluding 1983, Net additions = Additions - (2 * Retirements)

Source: FERC Form No. 1, for years 1981-1992. pp. 202-204.

[4] Source: "History and Forecast as of January 1, 1993, Base Load Forecast." Florida Power & Light Company.

Forms Submittal of 1992 Integrated Resource Plan. April 1993, p.7.

Regression of Cumulative additions in transmission plant ($s) on Cumulative changes in load

m	138,303	b	291,516,967
se	26,212	se (b)	80,163,158
r-sq	0.76	se(y)	154,347,302
F	28	df	9
SS (reg)	6.63E+17	ss(resid)	2.14E+17

Average additions =

$180.17 /kW

PROJECTED SAVINGS FOR FP&L BY 2003												
SAVINGS	SRC "BEST PRACTICE" for TRC TEST	PSC ADJUSTMENTS	ADJUSTED SRC "BEST PRACTICE"	FPL RATIO	UTILITY TRC PORTFOLIO	UTILITY TRC PORTFOLIO: ADJUSTED SRC "BEST PRACTICE"	UTILITY RIM PORTFOLIO	UTILITY RIM: UTILITY TRC	PROPOSED GOALS	RATIO OF PROPOSED GOALS TO ADJUSTED SRC "BEST PRACTICE"	RATIO OF PROPOSED GOALS TO UTILITY TRC PORTFOLIO	RATIO OF PROPOSED GOALS TO UTILITY RIM PORTFOLIO
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
ENERGY	9,906,973	921,357	8,985,616	91%	2,814,335	31%	1,775,564	63%	1,113,200	12%	40%	63%
SUMMER	3,794,994	255,751	3,539,243	93%	1,626,734	46%	1,147,029	71%	939,800	27%	58%	82%
WINTER (	1,184,371	73,481	1,110,889	94%	835,969	75%	766,551	92%	635,500	57%	76%	83%

Notes:
[1] See page 5 of this exhibit: Summary of SRC "Best Practices" Cost-Effective Achievable Results--TRC Test
[2] Values are calculated in Table of PSC Adustments for FP&L. Calculation of SRC "best practice" savings for measures which are cost-effective according to SRC, but not classified as "UP" or "CUE" according to the PSC. See page 6 of this Exhibit.
[3] = [1] - [2]
[4] = [3]/[1]
[5] See FPL's Cost-Effectiveness Goal Results Report (CEGRR) pp. 39, 41.
[6] = [5]/[3]
[7] See FPL's CEGRR pp. 37, 40
[8] =[7]/[5]
[9] See FPL's Testimony of Steven R. Sim, Docket no. 930548-EG, March 18, 1994, Exhibit No. Document 1, pp. 1-3
[10] = [9]/[3]
Demand Side Management Goals, Document No. 930551-EI, Witness: Currier, Exhibit No._ (JEC-1)
[12]=[9]/[7]

PROJECTED SAVINGS
FOR FPC
BY 2003

SAVINGS	SRC "BEST PRACTICE" for TRC TEST	ADJUSTED SRC "BEST PRACTICE"	UTILITY TRC PORTFOLIO	UTILITY TRC PORTFOLIO: ADJUSTED SRC "BEST PRACTICE"	UTILITY RIM PORTFOLIO	UTILITY RIM PORTFOLIO: UTILITY TRC PORTFOLIO	PROPOSED GOALS	RATIO OF PROPOSED GOALS TO ADJUSTED SRC "BEST PRACTICE"	RATIO OF PROPOSED GOALS TO UTILITY TRC PORTFOLIO	RATIO OF PROPOSED GOALS TO UTILITY RIM PORTFOLIO
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ENERGY	1,278,823	1,159,891	1,994,354	172%	520,607	26%	374,846	32%	19%	72%
SUMMER	246,057	229,475	665,406	290%	292,537	44%	242,009	105%	36%	83%
WINTER (	154,719	145,120	993,305	684%	546,191	55%	497,586	343%	50%	91%

Notes:
[1] See page 5 of this exhibit: Summary of SRC "Best Practices" Cost-Effective Achievable Results--TRC Test
[2]=[1]* FPL[3]; FPC's SRC savings have been adjusted by multiplying the FPL Ratio, (See FPL table, column [4]), by
FPC's SRC "Best practice" savings for TRC, column [1].
[3] See Florida Power Corporation's Petition, Docket No. 930549-EG, March 18, 1994, Summary of all measures that pass TRC, p. 185
[4]=[3]/[2]
[5] See FPC's Petition, Docket No. 930549-EG, March 18,1994, Summary of all Measures that Pass RIM
[6] = [5]/[3]
Demand Side Management Goals, Document No. 930551-EI, Witness: Currier, Exhibit No._ (JEC-1)
[8] = [7]/[2]
[9] = [7]/[3]
[10] = [7]/[5]

PROJECTED SAVINGS FOR GULF BY 2003

SAVINGS	SRC "BEST PRACTICE" for TRC TEST	ADJUSTED SRC "BEST PRACTICE"	UTILITY TRC PORTFOLIO	UTILITY TRC PORTFOLIO: ADJUSTED SRC "BEST PRACTICE"	UTILITY RIM PORTFOLIO	UTILITY RIM PORTFOLIO: UTILITY TRC PORTFOLIO	PROPOSED GOALS	RATIO OF PROPOSED GOALS TO ADJUSTED SRC "BEST PRACTICE"	RATIO OF PROPOSED GOALS TO UTILITY TRC PORTFOLIO	RATIO OF PROPOSED GOALS TO UTILITY RIM PORTFOLIO
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ENERGY	768,711	697,220	215,127	31%	62,741	29%	43,919	6%	20%	70%
SUMMER	1,087,700	1,014,398	215,183	21%	147,866	69%	103,506	10%	48%	70%
WINTER (	77,132	72,347	195,604	270%	148,068	76%	103,648	143%	53%	70%

Notes:

[1] See page 5 of this exhibit: Summary of SRC "Best Practices" Cost-Effective Achievable Results--TRC Test

[2]=[1]* FPL[3]; GULF's SRC savings have been adjusted by multiplying the FPL Ratio, (See FPL table, column [4]), by GULF's SRC "Best practice" savings for TRC, column [1].

[3] See GULF's Petition, Docket No. 930550-EG, March 18, 1994, Totals for Measures Passing TRC Test, Schedule 1

[4]=[3]/[2]

[5] See GULF's Petition, Docket No. 930550-EG, March 18, 1994, Totals for Measures Passing RIM Test, Schedule 1

[6] = [5]/[3]

[7] See GULF's Petition, Docket No. 930550-EG, March 18, 1994, Gulf Power Company's Proposed conservation Goals 1994 through 2003. Demand Side Management Goals, Document No. 930551-EI, Witness: Currier, Exhibit No._ (JEC-1)

[9] = [7]/[3]

[10] = [7]/[5]

PROJECTED SAVINGS FOR TECO BY 2003

SAVINGS	SRC "BEST PRACTICE" for TRC TEST	ADJUSTED SRC "BEST PRACTICE"	UTILITY TRC PORTFOLIO	RATIO OF UTILITY TRC PORTFOLIO: ADJUSTED SRC "BEST PRACTICE"	UTILITY RIM PORTFOLIO	RATIO OF UTILITY RIM PORTFOLIO: UTILITY TRC PORTFOLIO	PROPOSED GOALS	RATIO OF PROPOSED GOALS TO ADJUSTED SRC "BEST PRACTICE"	RATIO OF PROPOSED GOALS TO UTILITY TRC PORTFOLIO	RATIO OF PROPOSED GOALS TO UTILITY RIM PORTFOLIO
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
ENERGY	1,004,012	910,638	919,000	101%	437,000	48%	206,000	23%	22%	47%
SUMMER	394,728	368,126	201,000	55%	151,000	75%	94,000	26%	47%	62%
WINTER (	120,855	113,356	339,000	299%	313,000	92%	273,000	241%	81%	87%

Notes:

[1] See page 5 of this exhibit: Summary of SRC "Best Practices" Cost-Effective Achievable Results--TRC Test

[2]=[1]* FPL[3]; TECO's SRC savings have been adjusted by multiplying the FPL Ratio, (See FPL table, column [4]), by TECO's SRC "Best practice" savings for TRC, column [1].

[3] See TECO's Petition, Docket No. 930551-EG, March 18, 1994. Florida Public Service Commission TRC Portfolio Annual Demand Side Management Goals and Average Ratepayer Impacts, Exhibit No._ (JEC-1) Document No. 2, p. 1 of 1.

[4]=[3]/[2]

[5] See TECO's Petition, Docket No. 930551-EG, March 18, 1994. Florida Public Service Commission RIM Portfolio Annual Demand Side Management Goals and Average Ratepayer Impacts, Exhibit No._ (JEC-1) Document No. 2, p. 1 of 1.

[6] = [5]/[3]

[7] See TECO's Petition, Docket No. 930551-EG, March 18, 1994, Tampa Electric Rim Portfolio Annual Demand Side Management Goals, Document No. 930551-EI, Witness: Currier, Exhibit No._ (JEC-1) Document No. 3, p.1 of 1..

[8] = [7]/[2]

[9] = [7]/[3]

[10] = [7]/[5]

SUMMARY OF SRC "Best Practices" COST-EFFECTIVE ACHIEVABLE RESULTS--TRC TEST									
	Year 2000			2010			2003		
	ENERGY GWH saved	Summer MW saved	Winter MW saved	ENERGY GWH saved	Summer MW saved	Winter MW saved	ENERGY GWH saved	Summer MW saved	Winter MW saved
FPC	989	187	123	1,955	384	228	1,279	246	155
GULF	651	1,026	62	1,043	1,232	112	769	1,088	77
TECO	766	312	95	1,560	588	181	1,004	395	121
FPL-N	598	266	109	1,096	462	181	747	325	131
FPL-C	1,349	559	153	2,470	999	257	1,685	691	184
FPL-S	6,156	2,294	786	10,550	3,913	1,063	7,474	2,780	869
Total FPL	8,103	3,118	1,049	14,116	5,374	1,501	9,907	3,795	1,184
Source: SRC Cost-Effective Achievable Results Tables, prepared by David Dismukes									

Table of PSC Adjustments for FP&L

Calculation of SRC "best-practice" savings for measures which are cost-effective according to SRC, but not classified as "UP" or "CUE" by the Public Service Commission

		Year 2000											
		ENERGY MWH saved				Summer kW saved				Winter kW saved			
Measure prefix	Measure Number	FPL-N	FPL-C	FPL-S	TO. FPL	FPL-N	FPL-C	FPL-S	TO. FPL	FPL-N	FPL-C	FPL-S	TO. FPL
					[1]				[2]				[3]
RSC	4A	0	0	0	0	0	0	0	0	0	0	0	0
RSC	4B	0	0	0	0	0	0	0	0	0	0	0	0
RSC	19A	0	0	0	0	0	0	0	0	0	0	0	0
RSC	19B	0	0	0	0	0	0	0	0	0	0	0	0
RSC	20A	10,751	28,650	113,079	152,480	5,435	11,850	54,056	71,340	547	2,384	1,138	4,069
RSC	20B	4,811	0	0	4,811	2,516	0	0	2,516	896	0	0	896
RSC	23A	0	0	0	0	0	0	0	0	0	0	0	0
RSC	23B	0	0	0	0	0	0	0	0	0	0	0	0
RSC	27A	0	0	0	0	0	0	0	0	0	0	0	0
RSC	27B	0	0	0	0	0	0	0	0	0	0	0	0
LT	4	1,004	1,175	2,351	4,530	0	0	0	0	0	0	0	0
SCD	6	0	0	0	0	0	0	0	0	0	0	0	0
SCD	7	0	0	0	0	0	0	0	0	0	0	0	0
SCD	14	0	0	0	0	0	0	0	0	0	0	0	0
SCD	15	0	0	0	0	0	0	0	0	0	0	0	0
SCD	16	512	0	0	512	75	0	0	75	166	0	0	166
SCD	17	2,131	0	2,699	4,830	559	0	17,891	18,450	404	0	856	1,260
SCD	26	270	4,401	22,320	26,991	56	924	4,093	5,074	0	0	0	0
SCD	27	0	0	0	0	0	0	0	0	0	0	0	0
VD	2	447	1,509	8,093	10,049	142	752	2,732	3,626	283	703	2,041	3,027
VD	3	486	1,865	7,534	9,886	150	908	3,467	4,525	195	585	1,956	2,736
VD	4	3,543	8,994	0	12,537	868	2,586	0	3,454	1,337	2,194	0	3,531
VD	5	14,965	20,397	84,577	119,939	3,996	5,032	20,285	29,313	6,089	4,796	13,733	24,618
VD	6	684	2,689	10,047	13,420	0	16	0	16	0	0	0	0
VD	7	1,508	7,635	30,187	39,330	37	200	818	1,064	0	0	0	0
LD	27	0	0	0	0	0	0	0	0	0	0	0	0
LD	28	4,417	19,032	71,394	94,844	211	882	3,249	4,341	67	291	1,129	1,487
LD	29	7,363	33,495	129,970	170,827	1,405	7,069	27,800	36,275	473	2,069	7,637	10,179
LD	30	678	3,596	12,102	16,377	0	0	0	0	0	0	0	0
RD	10	407	1,969	7,761	10,137	0	0	0	0	0	0	0	0
TOTAL													

		Year 2010												Year 2003		
		ENERGY MWH saved				Summer kW saved				Winter kW saved				ENERGY MWH saved	Summer kW saved	Winter kW saved
Measure prefix	Measure Number	FPL-N	FPL-C	FPL-S	TO. FPL	FPL-N	FPL-C	FPL-S	TO. FPL	FPL-N	FPL-C	FPL-S	TO. FPL	To.FPL	To.FPL	To.FPL
					[4]				[5]				[6]	[7]	[8]	[9]
RSC	4A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	4B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	19A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	19B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	20A	32,293	65,459	220,116	317,868	16,104	28,281	108,489	152,873	1,504	4,886	3,402	9,792	202,097	96,800	5,786
RSC	20B	15,742	0	0	15,742	7,964	0	0	7,964	2,421	0	0	2,421	8,090	4,150	1,353
RSC	23A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	23B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	27A	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RSC	27B	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LT	4	8,524	9,775	19,213	37,512	0	0	0	0	0	0	0	0	14,424	0	0
SCD	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCD	7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCD	14	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCD	15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
SCD	16	594	0	0	594	94	0	0	94	234	0	0	234	1,337	396	117
SCD	17	3,263	0	5,534	8,797	855	0	29,328	30,183	739	0	0	739	6,020	21,970	1,103
SCD	26	254	1,146	5,334	6,735	51	233	985	1,270	0	0	0	0	20,914	3,932	0
SCD	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
VD	2	1,043	3,309	18,539	22,891	345	1,772	6,726	8,842	662	1,585	4,814	7,062	13,902	5,191	4,234
VD	3	1,076	4,180	16,086	21,342	318	2,001	7,555	9,874	418	1,284	4,238	5,937	13,322	6,130	3,896
VD	4	6,638	15,526	0	22,164	1,687	4,866	0	6,553	2,656	3,917	0	6,574	15,426	4,384	4,444
VD	5	34,216	39,731	163,832	237,779	8,927	10,068	39,812	58,806	13,737	9,014	25,742	48,493	155,291	38,161	31,781
VD	6	1,058	3,993	16,714	21,765	0	42	0	42	0	0	0	0	15,923	24	0
VD	7	2,227	11,805	46,671	60,703	53	313	1,275	1,641	0	0	0	0	45,742	1,230	0
LD	27	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LD	28	6,119	24,925	97,807	128,851	291	1,153	4,444	5,888	93	381	1,546	2,020	105,046	4,805	1,647
LD	29	20,697	97,481	388,177	506,354	5,512	28,560	113,212	147,284	1,864	8,277	30,509	40,651	271,486	69,578	19,321
LD	30	1,597	8,463	28,489	38,549	0	0	0	0	0	0	0	0	23,028	0	0
RD	10	294	1,426	5,657	7,377	0	0	0	0	0	0	0	0	9,309	0	0
TOTAL														921,357	256,751	73,481

Notes:
[7] = ([4]/[1])^(3/10)*[1]
[8] = ([5]/[2])^(3/10)*[2]
[9] = ([6]/[3])^(3/10)*[3]

Source: SRC Report No. 7777-R8; "Electricity Conservation and Energy Efficiency in Florida: Technical, Economic and Achievable Results; Final Report." May 1993; pp. 37-72.

Selection of measures based on Public Service Commission decision. See Order No. PSC-93-1679-PCO-EG; "Fourth Order Establishing Procedure," pp. 14-20.

LEAF Proposed Annual Energy Goals				
FPL				
YEAR	UTILITY TRC PORTFOLIO; (ENERGY SAVINGS IN GWH)	LEAF-PROPOSED GOAL FOR 2003	LEAF GOAL AS A PERCENTAGE OF UTILITY TRC	LEAF ANNUAL GOALS
	[1]	[2]	[3]	[4]
1995	337		64%	215
1996	706		128%	901
1997	1,064		192%	2,039
1998	1,416		255%	3,617
1999	1,760		319%	5,621
2000	2,108		319%	6,731
2001	2,451		319%	7,826
2002	2,808		319%	8,967
2003	2,814	8,986	319%	8,986
[5] 2004				9,566
Notes:				
[1] Source: Summary of FP&L TRC achievable energy savings				
[2] Adjusted SRC "best practice" savings for TRC test				
[3] =[2]/[1] for year 2003				
and =[3] for 2003, for years 1999-2002				
and =20% * [3] for 2003; for year 1995				
and =40% * [3] for 2003; for year 1996				
and =60% * [3] for 2003; for year 1997				
and =80% * [3] for 2003; for year 1998				
[4] = [3] * [1]				
[5] = [4] for 2003 +[([4] for 2003 - [4] for 2001)/2]				

LEAF Proposed Annual Energy Goals				
FPC				
YEAR	UTILITY TRC PORTFOLIO; (ENERGY SAVINGS IN GWH)	LEAF-PROPOSED GOAL FOR 2003	LEAF GOAL AS A PERCENTAGE OF UTILITY TRC	LEAF ANNUAL GOALS
	[1]	[2]	[3]	[4]
1995	157		12%	18
1996	298		23%	69
1997	498		35%	174
1998	740		47%	344
1999	1,018		58%	592
2000	1,323		58%	770
2001	1,568		58%	912
2002	1,831		58%	1,065
2003	1,994	1,160	58%	1,160
[5] 2004				1,255

Notes:
[1] See Florida Power Corporation's Petition, Docket No. 930549-EG, March 18, 1994, Summary of all measures that pass TRC, p. 185
[2] = 86% * Adjusted SRC "best practice" savings for TRC test
[3] =[2]/[1] for year 2003
and =[3] for 2003, for years 1999-2002
and =20% * [3] for 2003; for year 1995
and =40% * [3] for 2003; for year 1996
and =60% * [3] for 2003; for year 1997
and =80% * [3] for 2003; for year 1998
[4] = [3] * [1]
[5] = [4] for 2003 + ([4] for 2003 - [4] for 2002)

LEAF Proposed Annual Energy Goals					
GULF					
YEAR	UTILITY TRC PORTFOLIO; (ENERGY SAVINGS IN GWH)	LEAF-PROPOSED GOAL FOR 2003	LEAF GOAL AS A PERCENTAGE OF UTILITY TRC	LEAF ANNUAL GOALS	
	[1]	[2]	[3]	[4]	
1995	20		65%	13	
1996	38		130%	49	
1997	65		195%	126	
1998	100		259%	259	
1999	128		324%	415	
2000	149		324%	483	
2001	172		324%	558	
2002	195		324%	632	
2003	215	697	324%	697	
[5] 2004				762	
Notes:					
[1] See GULF's Petition, Docket No. 930550-EG, March 18, 1994, Totals					
for Measures Passing TRC Test, Schedule 1					
[2] Adjusted SRC "best practice" savings for TRC test					
[3] =[2]/[1] for year 2003					
and =[3] for 2003, for years 1999-2002					
and =20% * [3] for 2003; for year 1995					
and =40% * [3] for 2003; for year 1996					
and =60% * [3] for 2003; for year 1997					
and =80% * [3] for 2003; for year 1998					
[4] = [3] * [1]					
[5] = [4] for 2003 + ([4] for 2003 - [4] for 2002)					

LEAF Proposed Annual Energy Goals

TECO

YEAR	UTILITY TRC PORTFOLIO; (ENERGY SAVINGS IN GWH)	LEAF-PROPOSED GOAL FOR 2003	LEAF GOAL AS A PERCENTAGE OF UTILITY TRC	LEAF ANNUAL GOALS
	[1]	[2]	[3]	[4]
1995	106		20%	21
1996	214		40%	85
1997	323		59%	192
1998	433		79%	343
1999	541		99%	536
2000	646		99%	640
2001	746		99%	740
2002	835		99%	828
2003	919	911	99%	911
2004	999		99%	989

Notes:

[1] See TECO's Petition, Docket No. 930551-EG, March 18, 1994. Florida Public Service Commission TRC Portfolio Annual Demand Side Management Goals and Average Ratepayer Impacts, Exhibit No._ (JEC-1) Document No. 2, p. 1 of 1.

[2] Adjusted SRC "best practice" savings for TRC test

[3] =[2]/[1] for year 2003
and =[3] for 2003, for years 1999-2002, & 2004
and =20% * [3] for 2003; for year 1995
and =40% * [3] for 2003; for year 1996
and =60% * [3] for 2003; for year 1997
and =80% * [3] for 2003; for year 1998

[4] = [3] * [1]