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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of:

COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (FLORIDA POWER & LIGHT COMPANY).	DOCKET NO. 130199-EI
COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (DUKE ENERGY FLORIDA, INC.).	DOCKET NO. 130200-EI
COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (TAMPA ELECTRIC COMPANY).	DOCKET NO. 130201-EI
COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (GULF POWER COMPANY).	DOCKET NO. 130202-EI
COMMISSION REVIEW OF NUMERIC CONSERVATION GOALS (JEA).	DOCKET NO. 130203-EM

VOLUME 5

Pages 1061 through 1289

PROCEEDINGS: HEARING

COMMISSIONERS PARTICIPATING:
CHAIRMAN ART GRAHAM
COMMISSIONER RONALD A. BRISÉ
COMMISSIONER LISA POLAK EDGAR
COMMISSIONER EDUARDO E. BALBIS
COMMISSIONER JULIE I. BROWN

DATE: Wednesday, July 23, 2014

TIME: Commenced at 9:33 a.m.
Concluded at 10:26 a.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

REPORTED BY: LINDA BOLES, CRR, RPR
Official FPSC Reporter
(850) 413-6734

APPEARANCES: (As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

P R O C E E D I N G S

(Transcript follows in sequence from Volume 4.)

CHAIRMAN GRAHAM: Good morning. Once again I'm glad to see that everybody has made it here safely today and everybody is looking pretty bright and chipper. This is day three of, of our hearings, and I think we all pretty much have a good understanding of each other and the flow, and I think this will be a very productive day.

Okay. It looks like we have some wisdom coming from one of our fellow Commissioners, Commissioner Edgar.

COMMISSIONER EDGAR: Thank you, Mr. Chairman.

I would just like to take a moment, and I appreciate you recognizing me to do so, but we have one of our longtime dedicated employees who today is her last day, Karen Dockham, who has worked for the Commission, I believe, a little over 30 years and for the State of Florida 35 years of dedicated service. Karen is in our IT department and was one of those people that I call on frequently when I'm having trouble with the computer, the printer, the Internet, and she is always right there with a smile and so helpful. And today is her last day with us and in service to the

State of Florida as a full-time employee. And I appreciate you giving me a moment just to recognize her good work.

CHAIRMAN GRAHAM: That sounds very good, and thank you very much.

Okay. We are -- SACE, you had a witness. Is your witness in yet, or do we need to move on down to Sierra Club's witness?

MS. TAUBER: Mr. Chairman, our witness is here.

CHAIRMAN GRAHAM: Okay.

MS. TAUBER: And so SACE would like to call Karl Rábago. And, Mr. Chairman, I'll note that Mr. Rábago needs to be sworn in.

CHAIRMAN GRAHAM: Mr. Rábago, how are you this morning?

THE WITNESS: Okay. Thank you.

CHAIRMAN GRAHAM: If I can get you to raise your right hand.

Whereupon,

KARL R. RÁBAGO

was called as a witness on behalf of the Southern Alliance for Clean Energy and, having first been duly sworn, testified as follows:

EXAMINATION

BY MS. TAUBER:

Q Good morning, Mr. Rábago.

A Good morning.

Q Could you please state your full name and business address for the record?

A My name is Karl R. Rábago. My business address now is 44 Briary Road, Dobbs Ferry, New York, and I operate a business called Rábago Energy, LLC.

Q On whose behalf are you testifying?

A SACE.

Q Mr. Rábago, on May 19th, 2014, did you cause to be, cause to be prefiled direct testimony consisting of 34 pages in question and answer format?

A I did.

Q Do you have any changes to that testimony?

A Only, as I just noted, my address has changed since the time I filed the testimony to that that I just spoke onto the record.

Q Okay. Other than those, that change, if I asked you the same questions today, would your answers be the same?

A They would.

MS. TAUBER: Mr. Chairman, at this point I'd like to have Mr. Rábago's direct testimony read into the record as if given orally from the stand.

CHAIRMAN GRAHAM: We will enter his prefiled direct testimony into the record as though read.

BY MS. TAUBER:

Q Thank you. Mr. Rábago, did you also cause to be prefiled six exhibits numbered KRR-1 - KRR-6, which have also been identified as hearing Exhibits 75 through 80?

A Yes.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Commission review of numeric conservation goals (Florida Power & Light Company).	)	DOCKET NO. 130199-EI
In re: Commission review of numeric conservation goals (Duke Energy Florida, Inc.).	)	DOCKET NO. 130200-EI
In re: Commission review of numeric conservation goals (Tampa Electric Company).	)	DOCKET NO. 130201-EI
In re: Commission review of numeric conservation goals (Gulf Power Company).	)	DOCKET NO. 130202-EI

TESTIMONY OF KARL R. RÁBAGO
ON BEHALF OF THE SOUTHERN ALLIANCE FOR CLEAN ENERGY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS FOR THE RECORD.

A. My name is Karl R. Rábago. My business address is 2025 East 24th Avenue, Denver, Colorado.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am the principal of Rábago Energy LLC, a Colorado limited liability company.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Southern Alliance for Clean Energy ("SACE").

Q. PLEASE SUMMARIZE YOUR EDUCATION AND WORK EXPERIENCE.

A. I earned a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.M. degrees in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. I served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. I have also worked for more than 20 years in the electricity industry and related fields. I have served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, I have served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, I founded and became the principal of Rábago Energy LLC. I also currently serve as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the Board of Directors of the Interstate Renewable Energy Council (2012-present). My education and work experience is set forth in detail on my resume, attached as Exhibit KRR-1.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION (THE "COMMISSION")?

A. No. I have testified under oath before several state regulatory agencies, including the North Carolina Utilities Commission, the Virginia State Corporation Commission, the Georgia Public Service Commission, the Louisiana Public Service Commission, the Michigan Public Service Commission, the District of Columbia Public Service Commission, and before Congress and state legislatures, including most recently the Minnesota State Senate and House of Representatives.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my testimony is to make two key points regarding the solar photovoltaic ("solar PV") pilot programs administered by Florida Power & Light Company, Duke Energy Florida, Inc., Tampa Electric Company, and Gulf Power Company (the "Companies"). First, the Companies should substantially revise and continue their solar PV programs. Second, the Companies' solar programs should be revised to improve valuation techniques for solar PV in order to more accurately characterize solar PV cost effectiveness, and the Companies should be directed to improve their solar PV program structure and approach with a view to supporting the development of a self-sustaining solar PV market in Florida.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission disapprove the Companies' requests to cancel their solar PV programs in favor of a substantial revision to those programs. In particular, I recommend that:

- The Companies should be directed to develop, in conjunction with Commission staff and stakeholders, a Value of Solar Methodology similar to that now in place in Minnesota, and consistent with best practice guidance provided in the IREC "Regulator's Guidebook" relating to distributed solar valuation,
- The Companies should be further directed to use Value of Solar analysis in lieu of current cost-effectiveness tests to inform solar PV program structure, and
- The Companies should be directed to establish distributed solar PV programs that are focused not on compliance, but on supporting the emergence of a self-sustaining competitive market for distributed solar PV.

Q. WHAT MATERIALS DID YOU REVIEW IN PREPARING YOUR TESTIMONY?

A. I reviewed the original applications and supporting testimony filed by the Companies, as well as the Companies' responses to interrogatories and requests for production of documents submitted by SACE and Sierra Club.

Q. WHAT LEGAL AND POLICY PROVISIONS SUPPORT YOUR TESTIMONY, FINDINGS, AND RECOMMENDATIONS REGARDING IMPROVED ANALYSIS AND PROGRAM DESIGN FOR DISTRIBUTED SOLAR PV?

A. There is abundant support in Florida statutes and policy for advancement of clean renewable energy resources that reduce emissions and promote generation diversity. These include:

- Florida State Comprehensive Plan, Section 187.201, Florida Statutes (as amended 2008) – relating to improvement of air quality, reduction of emissions, promotion of alternative energy resources, promotion of solar energy technologies, promotion of low-carbon emitting power plants, and development of more secure energy resources.
- Florida Energy Efficiency Conservation Act (FEECA), Section 366.80, et seq., Florida Statutes – relating to legislative intent that the use of solar energy and other clean energy resources be encouraged; requiring Commission adoption of goals for demand-side renewable energy resources; requiring Commission consideration of costs and benefits to customers and the need for incentives; and requiring consideration of costs associated with regulation of greenhouse gas emissions.

Q. DOES FEDERAL POLICY ALSO IMPACT DISTRIBUTED SOLAR PV PROGRAMS?

A. Yes. In particular, I direct the Commission's attention to the recently reinstated U.S. EPA Cross-State Air Pollution Rule, which could provide opportunities to reduce regulatory risk and cost through increased reliance on distributed solar PV resources, and to forthcoming U.S. EPA regulations regulating greenhouse gas emissions from existing fossil fuel plants, which are expected to provide compliance flexibility mechanisms that favor distributed solar PV generation. I further note that the recently released National Climate Assessment that points out the serious risks facing Florida due to climate change resulting from greenhouse gas emissions.

IMPROVEMENTS TO THE COMPANIES' SOLAR PV PROGRAMS

Q. HAVE YOU REVIEWED THE COMPANIES' SOLAR PV PROGRAM

INFORMATION?

A. Yes, and based on that review, I have several recommendations for improving program design. My recommendations are informed by my own experience in program management as a utility executive, and by my familiarity with many other solar PV programs.

Q. WHAT ARE YOUR FINDINGS ON REVIEW OF THE COMPANIES' SOLAR PV PROGRAMS?

A. The Companies programs have resulted in valuable installations of distributed solar PV at homes, businesses, and schools. These systems will be generating clean, climate-proof, drought-proof, flat-priced electricity for decades to come. While the amount of distributed solar generation in Florida remains extremely small, the programs launched by the Commission hint at much greater potential for clean solar generation at or very near the point of consumption in Florida, to the benefit of ratepayers, the utilities, and society. However, the Companies' compliance-oriented approach to distributed solar PV severely constrained the opportunity reveal the benefits of solar rebate investments and to realize market transformation benefits in their service territories and therefore to maximize utility, ratepayer, and societal benefits that could have been obtained.

Q. WHAT DEFICIENCIES DO YOU FIND IN THE COMPANIES' SOLAR PV PILOT PROGRAMS?

A. My concerns are in two categories. First, I have concerns about the structure and operation of the solar PV pilot programs. The way in which the programs were conducted had significant negative impacts on the evaluation of the programs. Second, I have concerns about the metrics used to judge the cost-effectiveness of the Companies' solar PV pilot programs.

Q. WHAT ARE YOUR CONCERNS ABOUT SOLAR PV PROGRAM STRUCTURE AND ADMINISTRATION?

A. Most obviously, it is apparent that the Companies lack experience and determination to make distributed solar succeed, as demonstrated by the fact that these solar pilots had to be launched by Commission order as late as 2009, a time when many utilities in many less sunny states and nations were moving into mature and successful program structures. The numbers of customers taking advantage of the incentives demonstrates the pent-up demand for solar in Florida that existed in 2011 when programs started operating, and continues today.

Q. WHAT OTHER CONCERNS DO YOU HAVE?

A. The Companies reveal a mixed attitude to distributed solar PV. On the one hand, they declare distributed solar PV pilot programs as conclusively uneconomic for failure to pass DSM cost-effectiveness tests. Then they oppose any further efforts to support distributed solar PV deployment because, in the words of FPL witness Koch, "[t]he Solar Pilots have run for sufficient time to fully understand their performance and results, and they are scheduled to expire at the end of 2014." Witness Guthrie from DEF commented that in three years, installed price reductions did not meet expectations, but cited no efforts or explanation for that failure except that the Company now questions "if the rebates are truly incentivizing the market to reduce costs." Witness Guthrie further testifies that customer-owned solar has become "more viable and less expensive," and at the same time, the programs "fail the cost-effectiveness screens." On the other hand, witness Guthrie testifies, and I agree, that if the Commission decides to maintain the solar programs, new future programs should eliminate subsidization, leverage scale and scope to lower installed costs, account for and minimize integration costs, and gather and analyze meaningful data regarding solar deployment.

Q. CAN YOU DETAIL YOUR FINDINGS REGARDING THE COMPANIES' EVALUATION OF DISTRIBUTED SOLAR PV AND THE PILOT SOLAR

PROGRAMS?

A. This testimony addresses the programs and evaluations conducted by Florida Power & Light (FPL), Duke Energy Florida (DEF), Tampa Electric Company (TECO), and Gulf Power (Gulf). Several common themes emerge in the Companies' filings regarding the solar PV pilot programs and in their approach to distributed solar PV in general. These themes include:

- All of the Companies find that solar PV pilot programs were not cost-effective as evaluated. None considered any alternative approaches to evaluation of the programs.
- All of the Companies utilizes sophisticated avoided cost analysis in development of their resource plans and in screening alternative DSM programs. None applied this sophistication to the evaluation of the solar PV pilot programs or to the cost-effectiveness of distributed solar PV as a specific alternative resource.
- All of the Companies recognized the risk of fuel price volatility associated with increased reliance on natural gas; rather than integrate the avoidance of this risk into valuation of solar PV, the Companies limited their evaluation of fuel price risk to alternative price forecasts for entire resource plans.
- All of the Companies reported considering avoided generation, fuel, generation O&M, and transmission and distribution costs in evaluating alternative demand side resources. However, none of the Companies informed this analysis with the load-weighted and time differentiated value of solar PV generation. None of the Companies used Effective Load Carrying Capacity or other tools to fairly and fully assess the capacity credit that should be applied in valuing solar PV.
- All of the Companies reported that they do not develop specific cost estimates or detailed plans for transmission and distribution investments beyond a 10-year horizon, in some case as few as 5 years. As a result, they did not value transmission and

distribution cost avoidance during the entire 30+ years that a distributed solar PV system is likely to operate.

- None of the Companies reported assessing any value for the operational security and disaster-recovery benefits of distributed solar PV generation.
- None of the Companies assessed environmental regulatory risk beyond current compliance costs in valuing distributed solar PV as a specific technology option.
- All of the Companies reported that line losses at the transmission and distribution levels were correlated with load, but none of the Companies evaluated the value or cost-effectiveness of distributed solar PV in avoiding these load-weighted losses.
- None of the Companies integrated any location-specific analysis of the potential value of distributed solar PV into their evaluations.
- All of the Companies admitted that their solar PV pilot programs had enjoyed significant (from 25% to 38%) reductions in the installed cost of solar PV, and that their solar PV pilot programs had completely failed to contribute to those cost reductions.
- All of the Companies reported substantial popularity and rapid reservation of rebates in every program year of the solar PV pilots. All reported significant failure rates in converting reservations into installations. None reported any effort to regularize solar installation rates over the entire program year or to improve the completion rates for reservations.
- All of the Companies simultaneously cited the falling price of distributed solar as evidence of mature distributed solar markets and the failure of the programs to pass cost effectiveness tests.
- All of the Companies recommend termination of the funding for the solar PV pilots; none recommended improvements to the programs.

Q. WAS THERE ANY COMPANY-SPECIFIC INFORMATION THAT YOU WISH TO CITE IN PARTICULAR?

A. Yes. Though the quality and form of data provided in response to interrogatories and requests for production varied significantly, several noteworthy examples evidence a failure on the part of each Company to maximize the opportunity provided by the Commission's order to conduct pilot programs. In some cases, this evidence suggests efforts to ensure that distributed solar PV markets do not develop in Florida.

Q. WHAT DEF-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. DEF provided detailed information about solar PV technology assumptions. Many of these assumptions are inconsistent with broader market information. DEF relied on a 20-year measure life for solar PV even though virtually all module providers warrant their equipment for 25 years. DEF limits the value of the federal tax credit to 15% in spite of the fact that the credit is currently 30%. DEF assumes that residential solar costs $4.17/watt to install, even though prices are lower across Florida. DEF also includes marketing costs in its cost-effectiveness evaluations even though the programs require no marketing.

Q. WHAT GULF-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. Gulf reported that administrative expenses increased from 20% in 2011 to 30% in 2013 even as solar PV costs fell 38% during the same period. These excessive costs adversely impact cost-effectiveness. Gulf also reported that it spends ratepayer funds to purchase natural gas price hedges, but does not include this cost in evaluating the benefits of solar PV.

Q. WHAT FPL-SPECIFIC EVIDENCE DO YOU WANT TO NOTE?

A. FPL takes the position of assessing a penalty against distributed solar PV based on "avoiding fuel-efficient new generation," though the basis for this approach is not explained in testimony or responses.

Q. DO YOU AGREE WITH THE COMPANIES' ASSESSMENT THAT THE SOLAR PV PILOT PROGRAMS SHOULD BE TERMINATED?

A. The Companies' Solar PV Pilot Programs should not continue in their present form. I have strong concerns about leaving control and management of the solar PV programs in the hands of the Companies without significant modification, oversight, and stakeholder involvement.

Q. DO YOU AGREE WITH THE COMPANIES' CONCLUSIONS THAT SOLAR IS NOT COST-EFFECTIVE AND AS A RESULT, THE SOLAR PV PROGRAMS IMPOSE UNFAIR RATE IMPACTS ON NON-SOLAR CUSTOMERS?

A. No. The Companies' conclusions in this regard are unsupportable for two reasons. First, the solar PV programs were not properly structured to achieve cost-effectiveness or the development of a self-sustaining market for distributed solar. In the face of rapid and continuing declines in the price installed price of solar PV, a properly structured solar PV program could leverage these cost improvements, the growing customer popularity of distributed solar, efficiencies that will emerge from more mature market infrastructure, and more effective rebate and incentive strategies to support market development. Second, the solar PV programs use inadequate and inappropriate cost-effectiveness criteria when evaluating distributed solar as a resource. Improvements in valuation of the full range of costs and benefits associated with distributed solar PV would support a different conclusion regarding cost-effectiveness.

Q. DO YOU AGREE WITH FPL WITNESS KOCH THAT SOLAR PV PROGRAM PROPONENTS BEAR A BURDEN OF PRODUCTION OR PROOF IN ORDER TO JUSTIFY A COMMISSION ORDER FOR THE IMPROVEMENT AND CONTINUATION OF THE SOLAR PV INCENTIVE PROGRAMS?

A. No. In light of the extensive policy support provided in Florida Law for the clean renewable energy, in particular, solar energy, it is the Companies' obligation to conclusively establish that the solar PV programs should be terminated. In light of the problems that I have discussed, they have not met that burden.

Q. WHAT OVERRIDING OBJECTIVES SHOULD GUIDE THE STRUCTURE AND OPERATION OF A SOLAR PV PROGRAM?

A. In my view the primary goals for a strong solar PV program should be:

- The program and incentives should ultimately lead to a self-sustaining rooftop/small scale solar energy market in Florida.
- The program should provide fair compensation for solar energy value and additional financial incentives that are economically efficient, i.e., incentives that prompt customers to make solar energy investments they would not otherwise make, without being excessive.

Q. WHAT INDICATORS SHOULD THE COMPANIES TRACK IN MONITORING THEIR SOLAR PV PROGRAMS?

A. The Companies should focus not just on numbers of systems, dollars, kilowatts, and kilowatt hours. For a pilot program that should translate into a full program, it is the direction that the numbers are moving that is most important, and whether continued progress is being made toward program objectives designed to achieve program goals. Some of the key indicators of a sound solar program include:

- Progressive reduction in the incentives stimulating customer investment in solar PV.
- Progressive and systematic reductions in system and component costs.
- Progressive reduction in the fraction of system cost represented by incentives.
- Progressive increases in solar PV capacity per dollar of program budget.
- Progressive increases in the numbers of solar contractors and full-time, year-round employees.

Q. WHAT FACTORS SHOULD THE COMPANIES TRACK IN ORDER TO UNDERSTAND STATEWIDE AND COMPANY-SPECIFIC SOLAR PV MARKET CONDITIONS?

A. The Companies' program managers should track several factors on an ongoing basis that could impact local solar market conditions in order to reach a judgment about those market conditions so as to inform the setting of economically efficient solar incentive levels. Factors impacting emerging solar markets are local, regional, national, and even international, and include:

- Local and regional solar installer workloads
- Availability of skilled workforce
- Local and regional economic conditions
- Local customer awareness
- Local markets for solar financing
- Other local economic incentives
- Utility incentive programs in Florida, especially adjacent utilities
- Regulatory and legislative policy development in Florida, the Southeast, and the United States
- National solar module prices
- National solar incentive levels and status of programs
- National tax policy and incentives relating to solar energy
- International solar incentive programs (which impact global solar module prices)

In combination, these factors can impact customer demand for incentives and program participation. For example, when prices for modules drop quickly, customer demand for incentives can grow quickly. If such a trend is long-term in nature, adjustments to incentive levels may be warranted. In fact, recent reductions in installed solar costs as well as the availability of substantial federal tax incentives have been drivers of downward adjustments in rebates and incentives across the United States.

Q. WHAT OTHER RECOMMENDATIONS DO YOU HAVE FOR A STRONG SOLAR PV PROGRAM?

A. I have several other recommendations. These include:

- Good solar PV programs feature regular meetings of program staff with solar installation contractors and stakeholders, featuring two-way dialogue about market conditions, program performance, administrative requirements, and other issues. These meetings provide invaluable "ground-truthing" for solar program managers.
- Program managers should continually review the state of the art in solar promotion programs to stay abreast of innovations and opportunities for program improvements.
- While solar PV programs should be designed to provide predictability regarding incentives and program requirements, it is also appropriate to grant flexibility to program managers to respond to unexpected or sooner-than-expected changes in solar PV market conditions. When program adjustments are required they should not be a surprise to the Commission or stakeholders.
- Program managers should also be prepared for increases in the average size of installed systems as solar prices fall. Larger system sizes consume larger incentives per customer, and in a fixed budget environment, potentially reduce the number of systems receiving incentives. On the other hand, per-unit fixed and system costs decline with system size, allowing for more kilowatts per incentive dollar expended.
- Robust solar PV programs should account for repeat customers. Distributed solar is modular in nature, meaning customers can install a system one year, and expand the system in later years as demand or household budget grows. These system expansion investments can be a relatively low cost path to valuable incremental market growth.

THE COMPANIES SHOULD CONDUCT A COMPREHENSIVE VALUE OF SOLAR ANALYSIS

Q. WHAT IS THE BENEFIT OF COMPREHENSIVE VALUE OF SOLAR (VOS) ANALYSIS FOR SOLAR PV?

A. Full and updated evaluation of resource value improves the chance that a forward-looking resource or program plan will strike the economically efficient balance in crafting robust and least-cost plans in the most cost effective manner possible. If a renewable generation resource is under-valued by the Companies, it will be under-selected and under-utilized in its plans. In my view this is precisely the situation with the solar PV programs run by the Companies. The cost-effectiveness tests applied do not account for all the value of solar, and, as a result, the Companies reach a conclusion that their solar programs should be terminated. A full VOS analysis is necessary. It is not enough to say that one resource is "expensive" compared to another unless the benefits of the competing resources are also assessed and compared. The Companies' cost-effectiveness evaluations suffer from this flaw.

Q. HOW DO UTILITIES TYPICALLY ASSESS THE VALUE OF DISTRIBUTED SOLAR PV?

A. Distributed solar resources have historically not fared well in traditional utility ratemaking systems, which often have a financial bias toward large, capital-intensive projects owned by the utility. Historically, these utility-owned projects, if successful, tend to maximize profits at the expense of the lowest cost and highest value for customers. Historically utilized preferences tend to assign higher value to dispatchable generation options with low capacity cost, while undervaluing several increasingly valuable and important components, such as fuel price volatility, regulatory (especially environmental) risk, water supply and availability risk, transmission infrastructure requirements, and others. Traditional avoided cost methodologies, designed to set energy payments based on current costs, can reduce the value of low- or zero-risk resources and long run marginal cost and risk reductions.

Q. IS THIS APPROACH EVIDENT IN THE COMPANIES SOLAR PV PROGRAMS?

A. Yes. The Companies use and report the installed capacity cost of solar PV, but do not assess and characterize the full value of solar in providing energy, capacity, transmission and distribution, risk-reduction, and other benefits. It also appears that the Companies' do not assign full credit to solar PV generation that will accrue to the utility and all ratepayers over the full 30+ year useful life of installed systems. In addition, each of the Companies' assigns a "lost revenues" cost to solar PV that fails to account for all costs that the utilities avoid. This over-calculation of costs negatively impacts the cost-effectiveness assessment.

Q. DOES THIS TRADITIONAL PROCESS PROPERLY ADDRESS RENEWABLE RESOURCES?

A. No. This traditional process has not addressed renewable resources properly. More and different data about value is required.

Q. CAN YOU ELABORATE FURTHER?

A. Yes. It is important to understand the coincidence or overlap of solar production with hourly prices, which informs the energy value and capacity credit that should be recognized for this resource. Capacity credit informs the value for avoided capacity, avoided transmission and distribution investment, line losses, and other values. The Company should also recognize value for the greenhouse gas benefits of solar energy as well as the reduced risk of environmental regulation that solar energy provides—very real economic risks even in the absence of current control costs. Traditional calculations tend to ignore all manner of risk, including fuel price and environmental regulation risks. In response to SACE's efforts to adduce the various value factors considered by the Companies for renewable resources, it appears that in spite of a high availability of the raw data, few of these value factors are considered and even fewer are quantified.

Q. HOW HAS DISTRIBUTED SOLAR VALUATION EVOLVED?

A. As the U.S. Department of Energy reported to Congress in 2007,

"Calculating [distributed generation] benefits is complicated, and ultimately requires a complete dataset of site-specific operational characteristics and circumstances. This renders the possibility of utilizing a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits of [distributed generation] highly improbable. However, methodologies exist for accurately evaluating "local" costs and benefits (such as [distributed generation] to support a distribution feeder). It is also possible to develop comprehensive methods for aggregating local [distributed generation] costs and benefits for substations, local utility service areas, states, regional transmission organizations, and the Nation as a whole.[1]"

Over the past two decades, a number of local studies have been conducted to calculate the benefits of distributed solar. Today, VOS analysis rests on a solid foundation of data that, if applied, can significantly improve the Companies solar PV program structure and evaluation.

VALUE OF SOLAR ANALYSIS

Q. WHAT IS VALUE OF SOLAR (VOS) ANALYSIS?

A. VOS analysis identifies and characterizes the value attributes of solar energy generation by thoroughly characterizing and quantifying the costs avoided by solar generation. Numerous VOS studies published over the past decade share a common general approach and fairly common general structure. A representative list of these studies is described in greater detail in attached Exhibit KRR-2, a recent report from the Rocky Mountain Institute's eLab

[1] U.S. DOE, "The Potential Benefits of Distributed Generation and the Rate-Related Issues That May Impede Its Expansion: Report Pursuant to Section 1817 of the Energy Policy Act of 2005," June 2007.

Project entitled "A Review of Solar PV Benefit and Cost Studies.[2]" While results vary depending on methodologies, local energy markets and other factors, research consistently suggests that distributed solar energy has value that significantly exceeds the Companies' and utility ratepayers' costs associated with stimulating distributed solar energy development. That value should be, but is not, reflected in the Companies' evaluation of their solar PV programs and in their characterization of solar PV in planning. As a consequence, the Companies propose less solar development, zero goals, and even termination of distributed solar PV incentives. The Companies propose less solar PV support than would be economically efficient and miss a valuable opportunity to support the growth of a distributed solar market in Florida.

Q. WHAT ARE THE BASIC ELEMENTS OF DISTRIBUTED SOLAR VOS ANALYSIS?

A. VOS analysis is an expansion on a full avoided cost approach that adds a long term valuation perspective, including, as appropriate and quantifiable, social costs and benefits. There are two basic steps: first, benefits and costs are identified and grouped, then, second, the benefits are quantified. These steps are essentially the same as traditional ratemaking functions inherent in cost of service analysis. The focus is on the net value that distributed resources bring to utility and grid finances and operations.

Q. IS THE CALCULATION OF VOS MARKET DRIVEN?

A. Yes. VOS calculations are, at heart, avoided cost calculations that embrace a full range of costs avoided by distributed solar generation, including savings over the life of the solar generation system. So the source of the value of solar is in the market costs avoided and market benefits received. As explained earlier, solar valuation studies offer improved

[2] "A Review of Solar PV Benefit and Cost Studies," Rocky Mountain Institute eLab Report, April 2013. ("RMI eLab Report") Available at: http://www.rmi.org/Content/Files/eLab-DER_cost_value_Deck_130722.pdf.

market pricing signals over traditional avoided cost calculations, which ignore long-term risk, especially fuel price and environmental regulatory risk. My own experience with Austin Energy's VOS methodology is that the calculated value of solar better reflects market conditions and the value of solar investments than short-term avoided cost calculations and base rate calculations established in prior years based on historical test year costs.

Q. WHAT ARE THE BENEFITS AND COSTS STUDIED IN VOS ANALYSIS?

A. The benefits and costs are those that accrue to the utility and its ratepayers as a result of the satisfaction of the demand for electricity services from a distributed solar facility in lieu of the Companies' use of current and planned system resources to meet that demand. The value of solar to the Companies, as a renewable distributed generation resource, must be calculated in a very different manner from traditional capital- intensive, remote central station projects. A value of solar analysis also differs from other cost-effectiveness analyses conducted from a societal perspective in that customer investment and costs are typically omitted. At a high level, the costs and benefits to the Company and ratepayers associated with distributed solar energy generation systems include:

- Energy: The basic electrical energy created by the distributed solar system, plus a credit for line-loss savings that accrue because distributed solar displaced generation from remote, central station plants.
- Capacity: Also referred to as "demand." Capacity values capture the avoided capital investments in generation, transmission and distribution that flow from distributed solar generation units.
- Grid Support (Interconnected Operations Services): Often referred to as "ancillary services." These benefits include affirmative provision of services and avoidance of costs related to a range of services inherent in maintaining a reliable, functioning grid

network. This grid support or ancillary services include, at both the transmission and distribution level, reactive supply and voltage control, regulation and frequency response, energy and generator imbalance, scheduling, forecasting and system control and dispatch.

- Customer benefits: Customers accrue a number of benefits from hosting and operating distributed solar systems including reputational, community participation, bill management and stability, and efficiency support benefits. While some of these benefits do not accrue to the utility, some do, like reduced bad debt and delayed payment costs that accompany self-generation.
- Financial and security: These benefits generally reduce both the cost and risk associated with maintaining reliable electric service for customers, especially in the face or variable regulatory, economic, and grid security conditions. These benefits include utility fuel price volatility control, and costs associated with emergency customer power and outages, as well as more rapid and less costly recovery from outage events.
- Environment: Distributed solar creates benefits in reducing the supply portfolio costs associated with control of criteria pollutants, greenhouse gas emissions, water use, and land use. Where control regimes exist, these costs may be reflected in the cost of operating polluting resources. Distributed solar valuation goes beyond traditional avoided cost approaches in recognizing that these resources also affirmatively reduce financial risks associated with compliance with future control regimes.
- Social: Distributed solar also generates social benefits associated with net job growth benefits compared to “conventional” generation options, increased local tax revenues, reduced occupational safety costs (such as black lung insurance), and others.

Q. HOW ARE THESE BENEFITS AND COSTS QUANTIFIED?

A. I previously cited a Rocky Mountain Institute study that assessed several quantification studies. My recommendation is that the Companies should be directed to develop a quantification methodology and value of solar calculation in consultation with a broadly based group of stakeholders.

Q. HAVE ANY OF THE STUDIES QUANTIFIED THE VALUE OF SOLAR PV IN FLORIDA?

A. Though a strong body of research exists on this topic nationally, I have found no studies based on Florida data. The RMI eLab Report that I cited earlier and attached to this report characterizes more than a dozen "value of solar" and other studies addressing solar PV costs and benefits. Among the more prominent researchers cited was Richard Perez. Richard Perez led a team that published a study titled "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania.[3]" That study modeled the value of a 15% peak load penetration of distributed solar electric generation at seven locations in the region. The model addressed the following values:

- Fuel Cost Savings
- O&M Cost Savings
- Security Enhancement Value
- Long Term Societal Value
- Fuel Price Hedge Value
- Transmission and Distribution Capacity Value
- Market Price Reduction
- Environmental Value
- Economic Development Value
- Solar Penetration Costs

[3] "The Value of Distributed Solar Electric Generation to New Jersey and Pennsylvania," Clean Power Research, November 2012. ("CPR NJ & PA Study 2012") Available at: http://mseia.net/site/wp-content/uploads/2012/05/MSEIA-Final-Benefits-of-Solar-Report-2012-11-01.pdf

- Generation Capacity Value

The study found that the total value of distributed solar ranged from $0.256 to $0.318 per kWh. A copy of the paper is attached at Exhibit KRR-3 and is offered as an indicator of how a comprehensive distributed VOS study can be conducted. More recently, the State of Minnesota Department of Commerce developed, and the Minnesota Public Utilities Commission approved a value of solar calculation methodology.

Q. PLEASE DESCRIBE THE MINNESOTA DEPARTMENT OF COMMERCE'S VALUE OF SOLAR METHODOLOGY AND ITS RELEVANCE TO YOUR RECOMMENDATIONS.

A. In 2013, the State of Minnesota enacted a law that created an option for electric utilities to offer a Value of Solar tariff as an alternative to net metering. The Value of Solar rate aims to compensate solar generators fairly for the value of their output, and to create an opportunity for utilities to fully recover their costs of providing service to those customers. After a widely-praised stakeholder process that was transparent and engaged dozens of utilities, business and government representatives, advocates and concerned citizens, the Minnesota Department of Commerce developed a value of solar methodology (Minnesota Methodology)[4]. That methodology is intended to guide the development of any Value of Solar tariff proposals in Minnesota, and is attached at Exhibit KRR-4.

Q. WHAT ARE THE MAJOR FEATURES OF THE MINNESOTA METHODOLOGY?

A. Key aspects of the Minnesota methodology include:

- A standard solar photovoltaic rating convention
- Methods for creating an hourly solar production time-series, representing the aggregate

[4] Minnesota Value of Solar: Methodology, MN Department of Commerce Division of Energy Resources, Clean Power Research (Jan. 31, 2014), available at http://www.cleanpower.com/wp-content/uploads/MN-VOS-Methodology-2014-01-30-FINAL.pdf.

output of all solar systems in the service territory per unit capacity corresponding to the output of a solar resource on the margin

- Requirements for calculating the electricity losses of the transmission and distribution systems
- Methods for performing technical calculations for avoided energy, effective generation capacity and effective distribution capacity
- Economic methods for calculating each value component (e.g., avoided fuel cost, capacity cost, etc.)
- Requirements for summarizing input data and final calculations in order to facilitate PUC and stakeholder review

Q. WHY DO YOU DIRECT THE COMMISSION AND THE COMPANIES TO THE MINNESOTA METHODOLOGY?

A. The Minnesota Methodology stands in stark contrast to the methodologies used by the Companies in their applications. The Minnesota Methodology demonstrates the comprehensive, objectively verifiable approach that can be developed when a broad range of stakeholder and expert opinions are focused on the solar valuation issue. As explained in the Minnesota Methodology, if a value of solar is set correctly, it will account for the real value of photovoltaic generated electricity, and the utility and its ratepayers will be indifferent to whether the electricity is supplied from customer-owned photovoltaic resource or from comparable conventional means. This valuation eliminates cross-subsidization concerns if incorporated in a tariff, and used in resource planning, it can provide market signals for the adoption of technologies that could significantly enhance the value of solar electricity, such as smart inverters. A properly conducted resource plan should include accurate valuation of all resources options, including solar. The Minnesota Methodology represents a detailed and well-documented example that the Companies could use to guide their work in correcting the deficiencies of their current processes.

Q. CAN STUDY RESULTS FROM OTHER JURISDICTIONS BE APPLIED DIRECTLY TO THE COMPANIES AND UTILITY OPERATIONS IN FLORIDA?

A. These studies were not based on specific data from the Companies' service territory or from data for Florida. Given the diversity of the data sets from which the studies are drawn, and the relatively high importance of energy and local costs in the estimation, it is reasonable to conclude that the value delivered by distributed solar in the Companies' service territory will be significant and likely higher than the current retail price for electricity. Growing experience with VOS analysis yields insights as to best practice in distributed solar valuation. I recently co-authored a report published by the Interstate Renewable Energy Council (IREC) that sets out current best practice for distributed solar PV valuation.

Q. PLEASE DESCRIBE THE IREC REPORT ON SOLAR VALUATION AND ITS RELEVANCE TO YOUR RECOMMENDATIONS.

A. In October 2013, IREC published a paper authored by Jason Keyes and myself, entitled "A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation" ("Guidebook").[5] The Guidebook, attached as Exhibit KRR-5, draws on many distributed solar valuation studies to recommend a framework for a methodology for performing a benefit/cost evaluation for distributed solar. The Guidebook's recommended approach differs greatly from the approaches taken by the Companies. Key principles underlying the methodology that my co-author and I recommended include reliance on data, transparency, reasonable evaluation of costs and benefits, and consistency in approach.

Q. WHAT DOES THE IREC GUIDEBOOK RECOMMEND REGARDING THE

[5] A Regulator's Guidebook: Calculating the Benefits and Costs of Distributed Solar Generation, Interstate Renewable Energy Council (Oct. 2013), available at http://www.irecusa.org/publications/.

SCOPING OF A BENEFITS/COSTS STUDY?

A. In the Guidebook we recommend that the Commission clarify a number of issues at the onset of a benefit/cost study, including:

- *What is the appropriate discount rate for evaluation of costs and benefits?*

  Studies typically use the utility weighted average cost of capital, though there is a strong argument for use of a risk-adjusted discount rate to reflect the performance characteristics of solar generation.

- *What is being considered – all solar generation or exports to the grid only?*

  Where net metering is being evaluated, it is appropriate to limit the evaluation to exported energy. However, for a two-part rate and full value of solar analysis, all generation should be evaluated.

- *Over what timeframe will the study examine the benefits and costs of solar resources?*

  The timeframe for analysis should reflect the useful life of solar resources, today typically 30 years, though there is a strong argument that a sensitivity evaluation should consider a useful life as long as 35 years.

- *What does utility load look like in the future?*

  Under traditional net metering arrangements, customer-sited distributed solar generation operates to reduce utility load. Under some structures, such as a feed-in tariff, distributed generation does not reduce load, but does contribute to utility energy and capacity requirements at or near the point of generation.

- *What level of market penetration for distributed solar generation is assumed in the future?*

  It is unreasonable to assume exponentially higher market penetration rates in the short term. Likewise, it is not reasonable to assume penetration rates that are artificially constrained. Sensitivity analysis can be useful to gauge the impacts of more reasonable penetration rates.

- *What models are used to provide analytical inputs?*

  Utility models such as Strategist are extremely useful in conducting integrated resource plan analysis, but often are constrained in their ability to model small-scale resources. Extrapolation of results to analyze these resources can induce errors. Full transparency and sensitivity analysis at varying scales of deployment, and with variation in other assumptions (such as the penetration rate of distributed storage technology) is essential to accurately model distributed solar generation.

- *What geographic boundaries are assumed in the analysis?*

  Solar resources may demonstrate improvements in availability due to geographic dispersion. Solar insolation values, which drive energy production, vary depending on location. These variations should be accounted for in study design.

- *What system boundaries are assumed?*

  Solar integration costs may vary the location where solar generation is cited. These factors extend beyond land and construction costs and should be accounted for in a study.

- *From whose perspective are benefits and costs measured?*

  I recommend that the Companies use a combined test that incorporates ratepayer impacts testing and societal cost testing.

- *Are benefits and costs estimated on an annualized or levelized basis?*

  A levelized cost analysis extending over the useful life of the solar resource is best for fully capturing the avoided costs and delivered benefits of solar generation.

Q. WHAT DATA SETS DOES THE GUIDEBOOK RECOMMEND TO CONDUCT A FULL BENEFITS/COSTS ANALYSIS FOR SOLAR GENERATION?

A. The Guidebook recommends that the utility obtain or develop the following data sets:

- The five or ten-year forward price of natural gas, the most likely fuel for marginal generation, along with longer-term projections in line with the life of the solar generation system.

- Hourly load shapes, broken down by customer class to analyze the intra-class and inter-class impacts of solar generation.
- Hourly production profiles for distributed solar generators, including south-facing and west-facing arrays.
- Line losses based on hourly load data, so that marginal avoided line losses due to solar generation can be calculated.
- Both the initial capital cost and the fixed and variable O&M costs for the utility's marginal generation unit.
- Distribution planning costs that identify the capital and O&M cost (fixed and variable) of constructing and operating distribution upgrades that are necessary to meet load growth.
- Hourly load data for individual distribution circuits, particularly those with current or expected higher than average penetrations of distributed solar generation, in order to capture the potential for avoiding or deferring circuit upgrades.

I believe that the Companies have assembled most, if not all, of this data in the course of ongoing resource planning and other activities. Where utility-specific data is not readily available, analysts may develop suitable estimation methods or use third-party data (such as PV-WATTS data for solar performance).

Q. WHAT CATEGORY OF BENEFITS FROM SOLAR GENERATION SHOULD BE ASSESSED?

A. Consistent with the Guidebook, I recommend that the following solar generation benefits be addressed by the Company in an analysis:

- Energy – Based on not running a gas-fired plant

- System Losses – Based on marginal losses
- Generation Capacity – Using Effective Load Carrying Capability or similar analysis
- Transmission and Distribution Capacity – Not limited to large planning increments
- Grid Support Services – Evaluation of ancillary services value
- Financial – Fuel price hedge
- Financial – Market Price Response
- Security – Stability and Resiliency
- Environment: Carbon & Other Factors – Residual (beyond compliance) benefits
- Social – Economic development

Q. WHAT COSTS SHOULD BE ASSESSED?

A. As discussed in the Guidebook, I believe it is appropriate to assess utility costs as well. These costs include direct utility costs and may include an assessment of lost revenues. I note that assumptions about administrative costs (such as billing costs) should reflect automated billing systems. Interconnection costs incurred solely by the customer should not be included. And finally, I reiterate that integration costs should be based on realistic assumptions about solar generation penetration rates.

Q. HOW DOES VOS RELATE TO INCENTIVE PAYMENTS MADE BY THE COMPANIES UNDER THEIR SOLAR PV PROGRAMS?

A. The calculated value of solar can serve as a benchmark indicator for payments a utility makes for third-party solar energy. As with the theory behind avoided cost calculation, VOS analysis quantifies the value equal to what it would cost either the utility or a third party to provide solar energy delivered to the point where the energy does its work. It establishes an economic “indifference price.” The Companies, however, appears to conduct no value-based analysis to inform either incentive levels or cost-effectiveness evaluations.

Q. WHAT IS THE RELATIONSHIP BETWEEN THE CALCULATION OF VOS AND

THE ANALYSIS OF SOLAR RESOURCES AS A FACTOR IN RETAIL RATES PAID BY RATEPAYERS IN GENERAL?

A. Because the VOS approach improves on the Companies' traditional avoided cost methodology, it indicates a compensation level that can be used to ensure net positive benefits to ratepayers. That is, once the value of solar is fully and accurately known, the Company can be assured that distributed solar enabled at a lower payment will generate excess value for the Company and its ratepayers. At volume, these cumulative excess benefits will exert downward pressure on rates, reflecting a value-to-price differential. The Company's practice today is not grounded in value analysis, but rather in strict regulatory compliance. Such practice provides no assurance of value in excess of cost. This represents a significant opportunity cost to the Company and its customers.

Q. DO SOLAR PROGRAM SUBSCRIPTION RATES INDICATE WHETHER THE INCENTIVE AND PAYMENT LEVEL REFLECTS THE VALUE OF SOLAR PV TO THE COMPANIES AND THEIR RATEPAYERS?

A. No. Program subscription rates indicate how investor-customers perceive payment levels under current market conditions. In some cases, the timing of program reservations can be a powerful indicator of poor program administration. Solar deployment markets will not mature to efficiency in feast/famine cycles. Releasing an entire year's worth of incentives in a short period of time will encourage rapid subscription, but as the Companies have all testified, rapid reservation does not necessary mean high completion rates or the development of more efficient markets.

Q. IN SUMMATION, WHAT SHOULD THE COMMISSION AND THE COMPANIES REASONABLY CONCLUDE BASED ON THE MANY PUBLISHED DISTRIBUTED VOS STUDIES?

A. From published VOS research, the Commission and the Companies can and should reasonably conclude that:

- Distributed solar systems in the Companies' service territories likely have value that will exceed the payment required to facilitate wider deployment of solar as a generation resource.
- Because distributed solar value exceeds the cost to facilitate deployment, increased deployment of distributed solar will put downward pressure on rates.
- Value of solar analysis coupled with greater market development can support and confirm the cost-effectiveness of solar PV, that is, the availability of distributed solar at costs that are less than value.

In sum, distributed solar value analysis enables the Commission and the Companies to benchmark the resource value of the distributed solar option and to conclude that the Companies should move forward with a revised solar PV program structure that advances the deployment of distributed solar in the Companies' service territories beyond the limits of previous programs, and, of course, current proposals.

VOS, AVOIDED COST, AND COST-EFFECTIVENESS TESTS

Q. EARLIER IN YOUR TESTIMONY, YOU DISCUSSED AVOIDED COST METHODOLOGY. CAN YOU DISTINGUISH BETWEEN VOS AND TRADITIONAL AVOIDED COST CALCULATIONS?

A. Yes. Avoided cost analysis differs from VOS analysis in two key ways. First, most avoided cost analysis is not a "full avoided cost" calculation. Second, traditional avoided cost analysis differs from more far-reaching, forward-looking analyses used to evaluate new resource additions. A major difference between the two approaches relates to risk. Not all resources bear the same risks. Risk is not well addressed even in full avoided cost methodologies. A resource that depends on long-term availability of fuel at an affordable price is very different from distributed solar, which has no fuel cost, now or in the future.

This risk of price volatility is not captured in avoided cost calculations or in cost-effectiveness tests currently utilized. Risk, therefore, is either ignored or undervalued in current evaluation methodologies.

Q. PLEASE EXPLAIN HOW RISK VALUATION IMPACTS RESOURCE VALUATION AND COST-EFFECTIVENESS EVALUATION.

A. Undervaluing fuel volatility risk and other risks means that resource options like distributed solar is seen to avoid less cost than it actually does. This results from adjustments made to traditional ratemaking and cost recovery decades ago. Utilities are increasing their dependence on generation run on fuels with volatile pricing patterns—natural gas, in particular. They use pass-through cost recovery mechanisms for fuel costs in fuel cost reconciliation charges or "fuel charges," as they are often called. Generally, regulations approved the addition of fuel costs recovery riders on customer bills, over and above basic rates for electricity to address potential regulatory lag issues arising from price volatility.

As a result, utility finances are largely immunized from the deleterious impacts of regulatory lag in fuel cost recovery, but also less sensitive to fuel price volatility than even their customers. The typical "peaker" approach to avoided cost calculations confirms this—it is a methodology that essentially gives no value to resources that reduce fuel price volatility and instead affirmatively favors resources with low capacity costs, even if the long-run fuel costs of the resource are extremely variable. By undervaluing distributed solar, this approach encourages a utility to procure or support solar at a sub-optimal levels in its planning, systematically rejecting resources that reduce portfolio exposure to fuel price volatility risk.

A similar undervaluation arises regarding security risk and vulnerability to disruptions due to natural and man-made events and risks associated with obtaining water at affordable prices, for example. Of course, greenhouse gas regulation and other environmental regulatory risks (such as that associated with coal ash pond spills) add additional risk. Economic efficiency is maximized by an analysis that quantifies the full future stream of benefits and costs avoided over the full operational life of distributed solar and expressly addresses the risk associated with all costs over the life of each resource option. There is significant value in a generation resource that has no fuel or water cost or environmental regulatory cost over its entire life—a value appears to be largely ignored in the Companies' planning process and, in particular, in the goal setting and solar PV program evaluation processes. Understanding risk reduction value of all types associated with increased deployment of solar PV is key to constructing an optimally diverse portfolio of resources and to evaluating program costs and benefits.

Q. ARE THERE FUTURE COSTS AND/OR BENEFITS THAT SHOULD BE INCLUDED IN EVALUATING THE VALUE OF DISTRIBUTED SOLAR, BUT WHICH ARE NOT FINITELY QUANTIFIABLE?

A. Some costs and benefits are not precisely quantifiable. There is an analytical risk in erroneous valuation. Undervaluing one "alternative" option is the same as overvaluing the incumbent or reference unit. Overvaluing an option might impose costs on ratepayers that could inflate rates. It is appropriate to reach a reasonable level of confidence about a value estimate before using it in resource evaluation decision. But, the field is hardly static. Avoided cost and VOS methodologies have improved over the past several decades. There are also some values that, while difficult to quantify, should be reviewed qualitatively as part of the process of resource plan development. For example, while the tax base and job creation benefits of distributed solar market penetration might not yet lend themselves to discrete quantification in a utility resource plan or explicit reflection in utility rates, job creation and other economic development benefits must be expressly reviewed in the planning exercises. Such factors often have a strong impact on market and regulatory risk.

Q. HOW WOULD FORWARD-LOOKING RESOURCE EVALUATION FURTHER IMPROVE THE EVALUATION OF ALTERNATIVES?

A. Avoided cost methodologies are an appropriate means for comparing the cost avoided when a single unit of energy from a Qualifying Facility is introduced into the grid on a year-by-year basis. Distributed solar systems, however, are long-lived, with high availability and low output degradation. This is why distributed solar programs should take a longer view than is taken with traditional avoided cost calculation. Levelized cost of energy calculations and production cost modeling exercises are explicitly focused on a resource's capability to meet the demand for energy over the life of the resource. They are not limited to traditional marginal cost calculations such as are used in setting avoided cost rates. The amount paid to stimulate the construction and operation of a new distributed system will likely yield thirty or more years of continued energy generation and benefit creation. The most common and appropriate way to account for this stream of benefits is to adjust a full avoided cost calculation by iterating it over the entire expected operating life of the system and then calculating a levelized present value of that stream of benefits.

Q. HOW DOES A LEVELIZED PRESENT VALUE OF A STREAM OF FULL AVOIDED COSTS CALCULATION POTENTIALLY IMPACT RATEPAYERS?

A. The approach of both conducting a full avoided cost calculation and then adjusting it for the forward looking stream of value puts evaluation of the resource alternative on a level evaluation playing field with other resources and with planned additions to the system. More importantly, it sets a benchmark for the price above which the utility and ratepayers would be adversely impacted, and below which both the utility and its ratepayers would benefit. It sets a fair level for testing for financial indifference. It is important to note that unlike utility-owned assets, distributed solar systems owned and operated by customers and third parties create no long term stranded cost risk for the utility. Performance or production payments at or below the full value of distributed solar are calculated to minimize such risk by only paying when energy is generated.

RECOMMENDATIONS

Q. PLEASE STATE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission disapprove the Companies' requests to cancel their solar PV programs and instead order a substantial revision to those programs. In particular, I recommend:

- The Companies should be directed to develop, in conjunction with Commission staff and stakeholders, a Value of Solar Methodology similar to that now in place in Minnesota and consistent with the best-practice recommendations in the Regulator's Guidebook on valuation of the benefits and costs of distributed solar generation.
- The Companies should be further directed to use Value of Solar analysis in lieu of current cost-effectiveness tests to inform solar PV program structure.
- The Companies should be directed to establish distributed solar PV programs that are focused not simply on minimal compliance, but on supporting the emergence of a self-sustaining competitive market for distributed solar PV. Staff and other stakeholders should have an explicit and formal role in this program development process.

Q. WHAT RECOMMENDATION DO YOU OFFER REGARDING COMMUNITY SOLAR PROGRAMS DISCUSSED BY THE COMPANIES?

A. I believe that community solar programs offer an important opportunity to make participation in the benefits of distributed solar an option for more customers and in more areas of a utility service territory. Community solar programs can be cost-effective, fair, and can help support the development of self-sustaining distributed solar markets. However, it is vitally important that these programs also be soundly designed and administered, and that cost-effectiveness analysis is supported by full VOS analysis. The

Interstate Renewable Energy Council has published a report entitled "Model Rules for Shared Renewable Energy Programs,[6]" attached at Exhibit KRR-6 that should be consulted prior to developing a proposal for community solar. While it is beyond the scope of this testimony to address the Companies' community solar programs in detail, I would note that the FPL proposal for a donation program for utility-owned solar projects in Docket No. 140070-EG is not a community solar program or a suitable alternative to customer-owned distributed solar generation. That proposal merely recycles a failed approach to solar PV development based on a charitable donation model.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[6] Model Rules for Shared Renewable Energy Programs, Interstate Renewable Energy Council (Jun. 2013), available at http://www.irecusa.org/regulatory-reform/shared-renewables/.

BY MS. TAUBER:

Q Mr. Rábago, did you prepare a summary of your testimony?

A I did.

Q Mr. Chairman, I would like to now ask the witness to read the -- read his summary.

A Mr. Chairman, members of the Commission, my name again is Carl Rábago. I'm the principal of Rábago Energy, a Colorado Limited Liability Company. I'm appearing as a witness on behalf of the Southern Alliance for Clean Energy.

My testimony offers my expert reactions and resulting recommendations from a review of the application materials and responses to requests for information from the utilities FPL, Duke, TECO, and Gulf Power. I bring to this testimony more than 24 years of experience working in the electric utility field. My experience includes service as a Public Utility Commissioner in the State of Texas, as a Deputy Assistant Secretary at the U.S. Department of Energy, as a utility executive and as a leader in several research and policy organizations around the United States.

The summary of my testimony is really, really relatively simple: Unless something changes in the way the utilities evaluate customer-owned solar energy and in the way the utilities approach and administer solar programs, Florida, one of the sunniest states in the nation, will continue to fail to realize the beneficial potential of a robust solar PV market. This continued state of affairs would be contrary to FEECA's aim to encourage the use of solar energy and demand-side renewable systems.

My testimony contains two main recommendations. First, the utility should continue to offer solar PV programs, but these programs should be substantially improved. I offer several structural and operational modifications.

Second, the utility should improve their valuation techniques. That is the way in which they assess the benefits and costs of demand-side solar PV. I recommend that the companies, in conjunction with Commission staff and stakeholders, develop a value of solar methodology instead of the current cost-effectiveness testing which fails to capture the full range of benefits of solar energy.

On the existing PV pilots, the companies' programs have resulted in -- the companies' programs have resulted in valuable installations of distributed solar. The amount of distributed solar though remains extremely small in Florida, but the pilots hint of a greater potential for distributed solar and should continue in an improved forum.

The programs and incentives provided should ultimately lead to a self-sustaining rooftop and small solar energy market in the relatively undeveloped Florida market. The program should provide for fair compensation for solar energy value. The program should focus on several key indicators, including systematic reductions and incentives per kW of installed solar, growth in the number of full-time solar related jobs, and, of course, systematic improvements in the kilowatts of installed capacity per program dollars spent.

On the valuation of solar, it's important that the utilities account for the full sweep of benefits that solar provides. I recommend a value of solar analysis which identifies and characterizes the value attributed to solar generation by thoroughly quantifying the costs avoided by solar generation. The costs include the benefits of reducing environmental compliance costs. FEECA requires that in setting these goals the Commission consider costs associated with regulation on the emission of greenhouse gases, for example. Distributed solar PV is set to be a compliance mechanism in a rule that was forthcoming at the time of the filing of my testimony regulating greenhouse gas emissions from existing power plants and has now been formally proposed by the EPA.

It's important to recognize the benefit of reducing risk of fuel volatility. None of the utilities integrated this recognized risk into their valuation of solar PV. Traditional calculations tend to ignore all manner of risk, in fact, including not just fuel price and environmental regulation risk. A value of solar analysis would capture some of this risk.

One utility suggests that the burden of proof in production rests with Intervenors, even as they admit they are not conducting in-depth analysis of solar. In the face of market-wide reductions in the cost of solar, the utilities still failed to find ways to improve the efficiency and effectiveness of their programs during the pilot period.

In my testimony I offer experience-based recommendations on effective solar program design, including that foundation on full value analysis, in an effort to point the utilities in a new direction. By contrast, the utilities propose inaction at the most data collection without goals, timelines, or performance metrics. The utilities' proposals and testimony reveal a focus only on compliance with the most narrow view of the Commission's requirements and not on creating programs that succeed in harvesting Florida's solar market potential.

I ultimately agree with the utilities on one key point that I made at the beginning of this statement. If the utilities are not required to change their approach to customer-owned distributed solar, they will continue to fail.

Thank you.

MS. TAUBER: Mr. Chairman, the witness is available for cross-examination.

CHAIRMAN GRAHAM: Okay. Let's start at the top. OPC.

MR. SAYLER: No questions.

CHAIRMAN GRAHAM: Department of Agriculture.

MR. HALL: No questions.

CHAIRMAN GRAHAM: NAACP.

MR. DREW: Good morning, Chairman. No questions.

CHAIRMAN GRAHAM: FIPUG.

MR. MOYLE: No questions.

CHAIRMAN GRAHAM: Sierra Club.

MS. CSANK: Good morning, Mr. Chairman. No questions.

CHAIRMAN GRAHAM: EDF.

MR. FINNIGAN: No questions, Your Honor.

CHAIRMAN GRAHAM: Florida Power & Light.

MR. BUTLER: No questions, Your Honor.

CHAIRMAN GRAHAM: Duke.

MS. TRIPLETT: No questions, sir.

CHAIRMAN GRAHAM: TECO.

MR. BEASLEY: We have no questions.

CHAIRMAN GRAHAM: Gulf.

MR. GRIFFIN: No questions, sir.

CHAIRMAN GRAHAM: Staff.

MS. CORBARI: No questions.

CHAIRMAN GRAHAM: Commissioners.

I guess there's no redirect.

MS. TAUBER: No redirect.

I'd like to move at this point the exhibits into the record.

CHAIRMAN GRAHAM: Okay. Which, which ones?

MS. TAUBER: KRR-1 through 8.

THE WITNESS: 6.

CHAIRMAN GRAHAM: I'm sorry.

MS. TAUBER: 1 through 6, which have been marked as hearing Exhibits 75 through 80.

CHAIRMAN GRAHAM: We will enter Exhibits 75 through 80 into the record.

(Exhibits 75 through 80 admitted into the record.)

MS. TAUBER: Thank you.

CHAIRMAN GRAHAM: Sir, thank you very much.

THE WITNESS: Thank you.

CHAIRMAN GRAHAM: Okay. We are going on to Sierra Club's witness.

MS. CSANK: Mr. Chairman, Sierra Club calls Mr. Woolf, and he will need to be sworn in.

Whereupon,

TIM WOOLF

was called as a witness on behalf of the Sierra Club and, having first been duly sworn, testified as follows:

EXAMINATION

BY MS. CSANK:

Q Hello, Mr. Woolf. Please state your full name and business address for the record.

A My name is Tim Woolf. I work at Synapse Energy Economics in Cambridge, Massachusetts.

Q And your business address, please.

A 485 Massachusetts Ave. in Cambridge, Massachusetts.

Q On whose behalf are you testifying today?

A I'm testifying on behalf of the Sierra Club.

Q And you said you're employed by Synapse Energy Economics. In what capacity?

A I'm a vice president there.

Q And have you prepared and caused to be prefiled direct testimony for these consolidated dockets?

A Yes, I have.

Q Do you have that with you today?

A Yes, I do.

Q If I were to ask you the same questions today, would you give the same answers?

A Yes, I would.

MS. CSANK: Mr. Chairman, Sierra Club moves to enter Mr. Woolf's prefiled direct testimony into the record as though read.

CHAIRMAN GRAHAM: We will enter his prefiled direct testimony into the record as though read.

MS. CSANK: Thank you.

BY MS. CSANK:

Q Mr. Woolf, did you prepare exhibits to your testimony titled TW-1 to TW-13 and hearing Exhibits 81 to 93?

A Yes.

Q Thank you.

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title and employer.

A. My name is Tim Woolf. I am a Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning and analysis. Our work covers a range of issues, including economic and technical assessments of energy resources; electricity market modeling and assessment; integrated resource planning; energy efficiency policies and programs; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including attorneys general, offices of consumer advocates, public utility commissions, environmental advocates, the US Environmental Protection Agency, the US Department of Energy, the US Department of Justice, the Federal Trade Commission and the National Association of Regulatory Utility Commissioners. Synapse has over twenty-five professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU). In that capacity, I was responsible for overseeing a considerable expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of DPU's energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; the review of smart grid pilot programs; and the review and approval of long-term contracts for renewable power. I also oversaw a variety of other DPU dockets, including several electric and gas rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director of the Association for the Conservation of Energy; a Staff Economist at the

Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Master's Degree in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a Bachelor of Science Degree in Mechanical Engineering and a Bachelor of Arts Degree in English from Tufts University.

Q. Please describe your professional experience as it relates to energy efficiency policies and programs.

A. Energy efficiency policies and programs have been at the core of my professional career. While at the Massachusetts DPU, I played a leading role in updating the Department's energy efficiency guidelines, in reviewing and approving the 2010-2012 three-year energy efficiency plans, in reviewing and approving energy efficiency annual reports, in leading a working group on rate and bill impacts, and advocating for the New England wholesale electricity market to include energy efficiency. I also co-chaired the Working Group on Utility Motivation as part of the State Energy Efficiency Action Network sponsored by the US Department of Energy and the US Environmental Protection Agency.

As a consultant, my work has encompassed all aspects of energy efficiency program design and implementation, including cost-benefit analyses, avoided costs, program budgeting, program assessment, utility financial incentives and other relevant regulatory policies. I am currently the lead technical consultant for the National Efficiency Screening Project. In addition, I recently completed three national studies on demand resource cost-effectiveness, including one for the US Department of Energy and the Federal Regulatory Commission. I have reviewed and critiqued utility energy efficiency policies and programs throughout the US, and I have testified on these issues in British Columbia, Colorado, Delaware, Kentucky, Massachusetts, Minnesota, Nevada, Nova Scotia, Québec, and Rhode Island. I have also represented clients on several energy efficiency collaboratives, where policies and programs were discussed and negotiated among a variety of stakeholders. I work for a variety of clients on energy efficiency issues, including consumer advocates, environmental advocates, regulatory commissions and the US Department of Energy.

Q. On whose behalf are you testifying in this case?

A. I am testifying on Sierra Club's behalf.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the goals of the electric utilities that are subject to the Florida Energy Efficiency and Conservation Act (the Utilities). I focus on Florida Power & Light Company (FPL) and Duke Energy Florida, Inc. (DEF), because they serve such a large portion of Florida's electricity demand. However, many of my findings and recommendations can and should be applied to all of the Utilities.

Also, much of my testimony addresses the Utilities' energy efficiency and load management programs. I also address demand-side renewable resources, primarily in Section 7. Throughout my testimony, I refer to the energy efficiency and load management programs as demand-side management (DSM), and I refer to the customer-sited renewable resources as demand-side renewables. I do not address supply-side efficiency goals.

Q. Have you previously testified before this Commission?

A. No.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

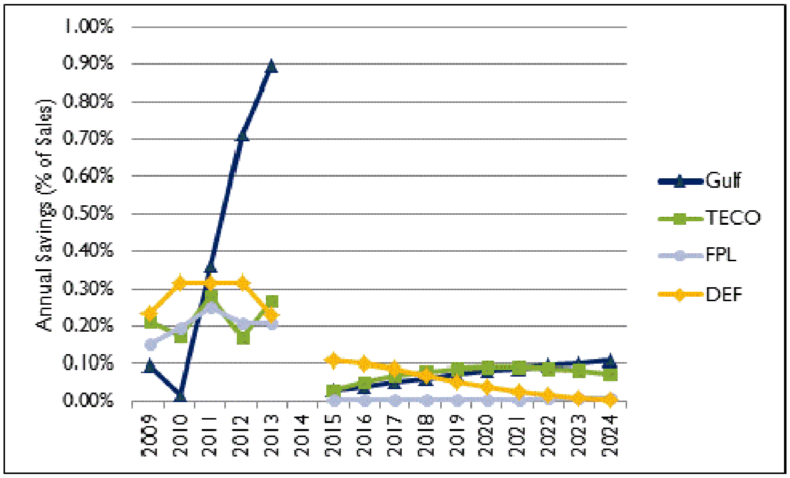
Q. Please summarize your primary conclusions.

A. My primary conclusions are summarized below. Additional details and citations are provided in the main body of my testimony.

<u>The Utilities DSM Goals Are Extremely Low</u>

By any measure the Utilities' proposed DSM goals are extremely low. Figure 2.1 compares the DSM goals proposed by FPL, DEF, Tampa Electric Company (TECO) and Gulf Power Company (Gulf) to these utilities' DSM savings in recent years.

Figure 2.1 Historic Savings and Proposed Energy Goals



As Figure 2.1 shows, the proposed goals depart dramatically from past DSM savings levels. For example, FPL achieved 214 GWh savings in 2013, but proposes to save 2.4 GWh in 2015. In other words, *FPL's proposed goals are one hundred times less than what FPL achieved in 2013*—a drop that my analysis below shows is entirely unwarranted.

The Utilities' historic DSM savings are well below industry practices in most other states. In 2011 over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, several states saved over 1.0 percent of retail sales. If the Commission were to accept FPL's proposed DSM goals, then FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country.

Figure 2.1 also shows that these four utilities propose very different DSM goals over the relevant ten-year period, from 2015 to 2024: DEF's goals, like FPL's, decline to almost nothing, while Gulf and TECO's goals increase modestly. This raises the question of why DEF would have such a dramatic decline in its goals, while other utilities are able to increase their goals over the same period.

These proposed DSM goals are not low because the DSM opportunities are not available or are not cost-effective—as the Utilities claims. The proposed goals are also not low because the Utilities have already achieved most of the DSM potential that is available, or that new building codes and appliance standards are going to eliminate DSM opportunities—as the Utilities claim.

These goals are extremely low because the Utilities have skewed the analysis by applying overly narrow definitions of cost-effectiveness, thereby significantly understating the value of DSM programs—the lowest-cost, lowest-risk resource. In addition, the Utilities' resource planning processes[1] contain fundamental flaws, leading to results that are not credible, that understate the value of DSM, and ultimately do not provide the Commission with the information necessary to set goals pursuant to FEECA.

The Utilities' DSM Screening Practices Understate the Value of DSM

The Utilities try to define cost-effectiveness in ways that understate the value of DSM. As a result, the Utilities' DSM screening practices are incorrect, misleading, and should not be used for the purpose of setting DSM goals. In particular:

- The Utilities' definition of cost-effectiveness does not take into consideration "the costs and benefits to the general body of ratepayers as a whole," as required by Section 366.82(3), Florida Statutes (F.S.).
- The Utilities ultimately only apply one DSM screening test—the Rate Impact Measure (RIM) test. Despite references to other tests, the Utilities use the RIM test as the sole criterion for proposing DSM goals. The RIM test should not be used to determine DSM cost-effectiveness. It has been rejected by essentially every state except Florida. There are better ways to address the important issue of DSM rate impacts.
- The Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, the Utilities significantly overstate their estimates of lost revenues—the key additional cost included in the RIM test.

[1] I use the terms resource planning processes and resource planning practices interchangeably to mean the Utilities' analytic methodology for resource planning.

- The Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by Section 366.82(3)(d). The Utilities also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

The Utilities' Resource Planning Practices are Fundamentally Flawed

In my 30 years of experience in reviewing and regulating DSM plans and integrated resource plans, I have never seen such opaque, convoluted, and misguided resource screening practices. In particular, the Utilities' attempt to incorporate DSM into their resource planning suffers from the following flaws:

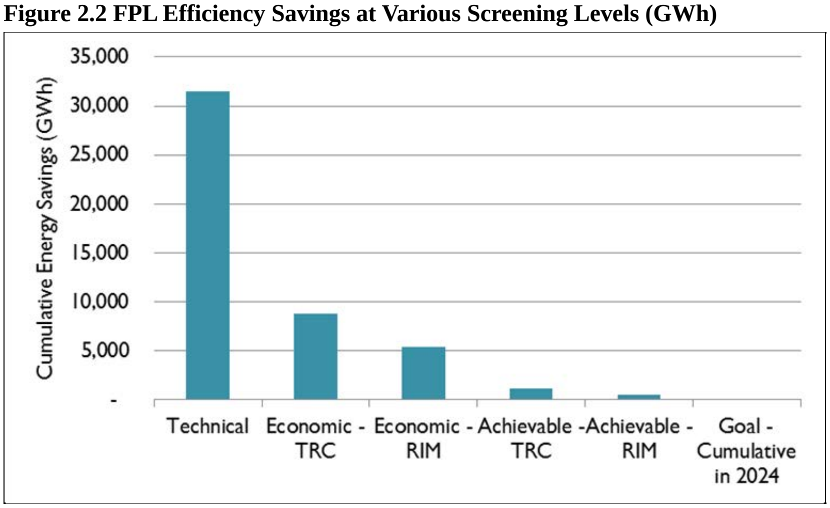
- The Utilities' technical potential estimates significantly understate the full technical potential for DSM in Florida by ignoring several efficiency technologies, and by applying an overly-stringent free-rider screen.
- FPL and DEF undervalue DSM by conducting two economic screens. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and "optimized" with supply-side resources.
- FPL's resource planning understates DSM capacity (i.e., MW) benefits by freezing in place several new generation options, including new combustion turbines and the Turkey Point Units 6 and 7. Thus, FPL ignores the potential for DSM measures to postpone, reduce or avoid these expensive new capacity requirements, and fails to account for key benefits of DSM.
- FPL's resource planning understates DSM energy (i.e., MWh) benefits by assuming that DSM measures can only be installed for meeting reliability needs. This simplistic assumption dramatically understates another key benefit of DSM.
- The Utilities' resource planning is unnecessarily complex and opaque. FPL claims that its complicated process is necessary to understand the economic impacts of DSM, but in fact FPL's process obscures and understates DSM benefits.

Consequently, the output of the process provides no meaningful information regarding the real value and implications of DSM.

The practices listed above conflict with the standard industry resource planning practices.[2] So much so that the results of the Utilities' aberrant practices are not credible and the Commission should not use them to set goals here.

Figure 2.2 shows the results of FPL's technical, economic and achievable estimates, demonstrating how a dramatic reduction in DSM potential occurs at each step. At the final step, due to FPL's incorrect practice of considering DSM only when it is needed to meet reliability needs (in MW), FPL eliminates nearly all potential DSM from its proposed goals—this is not a credible result.

Figure 2.2 FPL Efficiency Savings at Various Screening Levels (GWh)



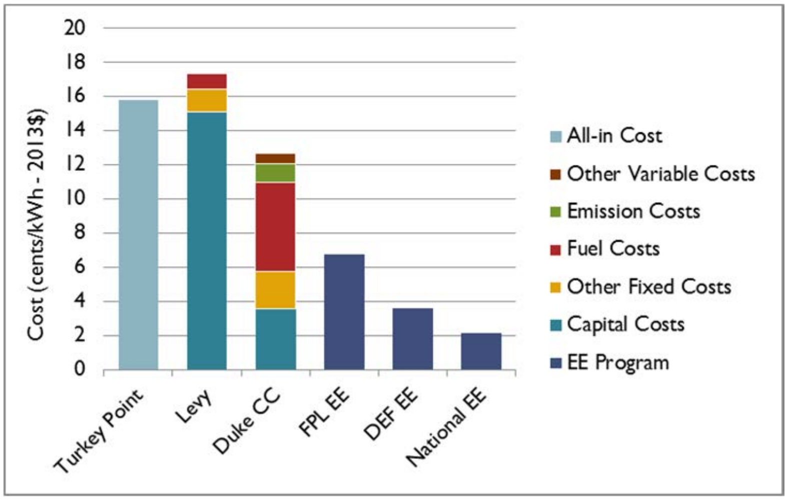
DSM costs significantly less than supply-side alternatives. Therefore, DSM can significantly reduce utility system costs and customer bills, a key fact that risks being obscured by the Utilities' incorrect analysis.

Figure 2.3 compares the levelized cost of saved energy from DSM to the levelized costs of the proposed Turkey Point and Levy nuclear facilities, and the estimated costs of the

[2] See, e.g., Synapse Energy Economics, *Best Practices in Electric Utility Integrate Resource Planning*, prepared for the Regulatory Assistance Project, 2013.

combined-cycle gas facility used by DEF in its resource planning process.[3] DSM is the clear winner, costing significantly less than alternative resources, contrary to what the Utilities try to argue by citing their flawed resource planning processes. Moreover, DSM helps mitigate the significant risks associated with these, more expensive supply-side resources.[4]

Figure 2.3 Cost of Generation Technologies versus the Cost of Saved Energy



Higher DSM Goals Would Lead to a Better Balancing of Costs and Rates

One of the key objectives in setting DSM goals is to strike the proper balance between reduced costs and the potential for increased rates. Striking this balance requires a much better assessment of rate impacts than the RIM test provides (even when correctly applied). It requires a reasonable assessment of (a) the potential rate impacts of the DSM proposed goals; (b) the potential for reducing customer costs and customer bills; and (c) the customer participation rates in the DSM programs. My analysis shows that:

- The rate impacts of the Utilities' proposed DSM goals will be so low as to be unnoticeable, and higher DSM goals would lead to very small rate impacts, if any.

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3 Levelized costs are the constant unit cost (in $/MWh) that, if incurred over a pre-determined period would have the same net present value as the stream of annual costs incurred over the same period.

4 Ceres, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know*, prepared by Ron Binz, Rich Sedano, Denise Furey, Dan Mullen, April 2012.

- Higher DSM goals would result in reduced costs, and therefore reduced bills.
- Higher DSM goals would result in greater DSM program participation, further offsetting any increase in rates that might occur as a result of DSM programs.

The Utilities Understate the Potential Value of Demand-Side Renewables

The Utilities significantly understate the potential value of demand-side renewable resources by not accounting for recent and anticipated cost trends in the PV industry; overstating customers' ability and interest in installing PV systems without utility support; and by omitting the avoided cost of GHG emissions.

Q. Please summarize your primary recommendations.

A. My primary recommendations are summarized below. Additional details are provided in the main body of my testimony.

DSM Goals. The Commission should set DSM goals[5] for the Utilities as follows:

- Energy (GWh) Savings. Each Utility should be required to achieve annual efficiency savings equal to one percent of retail sales by 2019.
- Capacity (MW) savings. Each utility should be required to achieve capacity savings such that the ratio of capacity-to-energy savings is consistent with the ratios that were achieved by the Companies in recent years. This will maintain the current balance between energy and capacity savings of the DSM programs.[6]

Demand-Side Renewables. The Commission should require the Utilities to continue to provide PV programs to their customers, with some modifications to the current programs as outlined below. The Commission should open a separate docket to investigate appropriate goals for customer-sited renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar photovoltaic (PV) systems.

[5] These goals do not include savings from demand-side renewable resources.

[6] This recommendation is not meant to suggest that the current balance between capacity and energy savings is ideal. It is merely meant to prevent the balance from becoming any worse.

Regulatory Support. The Commission should open a generic docket to investigate opportunities to establish a revenue decoupling mechanism to help remove the Utilities' financial disincentive to advance DSM. That docket should also investigate opportunities to establish shareholder performance incentives to help provide positive financial incentives for the Utilities to implement successful DSM programs.

Future DSM Screening. For future DSM planning and goal-setting purposes, the Commission should: (a) clarify that the RIM test should not be used for screening DSM programs; (b) clarify that a proper application of the TRC test should include the customer incentive provided by a utility, and participant non-energy benefits; (c) require reasonable estimates of GHG compliance costs be used in the base case analysis; and (d) present the results of the Utility Cost test for consideration by the Commission.

Future Resource Planning. For future DSM planning and goal-setting purposes, the Commission should require the Utilities to conduct resource planning processes that provide meaningful information for the purpose of setting DSM goals. In particular, the resource planning process should: (a) comport with standard industry resource planning practices; (b) be transparent with regard to decision-making processes, the results and interpretation of the results; (c) use the present value of revenue requirements as the primary criterion for selecting among different resource plans; (d) analyze numerous plans to optimize the combination of demand-side and supply-side resources; and (e) use reasonable estimates of free-rider impacts from measurement and verification studies, and not the overly simplistic payback criterion.

3. DEMAND-SIDE MANAGEMENT COST-EFFECTIVENESS TESTS

Q. Why is cost-effectiveness so important in setting goals DSM goals?

A. DSM is by far the lowest-cost resource available to meet customer needs. Efficiency resources reduce electric system costs and thereby reduce average customer bills. These cost- and bill-impacts are precisely what an economic regulator like the Commission oversees with the help of cost-effectiveness tests. When applied correctly, the tests can substantiate whether a particular resource or portfolio of resources is cost-effective.

DSM goal-setting is no exception. Notably, at least once every five years, FEECA requires the Commission to avail itself of the best available information regarding the cost-effectiveness of potential DSM, demand response, and demand-side renewable energy resources to set DSM goals. *See* Sections 366.81, 366.82(3)(a)-(d), (5)(b), F.S. Moreover, each year, the Utilities are required to provide the Commission with evidence of "lowest cost possible" planned energy, including the resources covered by DSM goals. *See* Rule 25-22.072, F.A.C. (incorporating by reference Form PSC/RAD 43-E (11/97)).

In setting DSM goals, the Commission must not lose sight of the fact that DSM can significantly reduce utility and customer costs. If DSM cost-effectiveness analyses are not properly defined or conducted, then the Utilities may implement an inappropriate amount of DSM, and their customers will pay more—potentially a lot more—than necessary for electricity services.

Q. Have the Utilities properly evaluated the cost-effectiveness of DSM in setting their DSM goals?

A. No. The Utilities' proposed DSM goals are way too low because the Utilities' cost-effectiveness screening is fundamentally flawed in ways that significantly understate the cost-effectiveness of DSM programs.

Q. Please describe how the remainder of this section is organized.

A. Since the DSM cost-effectiveness tests are so important to setting DSM goals, I dedicate a large portion of my testimony to them. First, I describe a national effort that provides useful guidance on the very issues of cost-effectiveness in these dockets. Second, I describe how cost-effectiveness is defined in Florida based on FEECA and the Commission's implementing regulations and orders. Third, I discuss my concerns with the way that the Utilities have defined and used cost-effectiveness tests for setting their DSM goals. Finally, I discuss several important benefits that the Utilities have omitted from their screening tests, particularly greenhouse gas (GHG) regulatory compliance costs and non-energy benefits associated with DSM programs.

The National Efficiency Screening Project

Q. What is the National Efficiency Screening Project?

A. The National Efficiency Screening Project (NESP) was recently formed to provide guidance on ways to improve efficiency screening practices. The NESP Team published a set of principles and recommendations for how states should reconsider and potentially modify their efficiency screening practices.[7] One of NESP's key recommendations is that each state should apply a framework—the Resource Value Framework (RVF)—to identify the most appropriate costs and benefits to consider when screening DSM programs. I will describe RVF and its relevance to the Utilities' DSM goals below.

Q. What is the NESP Team?

A. The NESP Team is led by a steering committee who oversees the entire initiative. I am a member of this steering committee, as the lead technical consultant. The NESP Team also includes project advisors, who assist in developing and refining NESP's key principles and recommendations. The project advisors are nationally-recognized energy efficiency experts who help capture perspectives from across the country. Finally, NESP project members, representing many organizations that support the NESP principles and recommendations, advance national and state campaigns to improve energy efficiency screening. The individuals and organizations that comprise the NESP Team are listed in the NESP Recommendations document cited above.

Q. What are the key elements of the Resource Value Framework?

A. The RVF includes several principles that each state should apply when designing its energy efficiency screening test:

- The Public Interest. The ultimate objective of efficiency screening is to determine whether a particular energy efficiency program, or portfolio of programs, is in the public interest.

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[7] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening* (March 2014), available at http://www.nhpci.org/projects/costbenefittesting.html.

- Energy Policy Goals. Efficiency screening practices should account for the energy policy goals of each state, as articulated in legislation, commission orders, regulations, guidelines and other policy directives. These policy goals provide guidance as to which efficiency programs are in the public interest.
- Symmetry. Efficiency screening practices should ensure that tests are applied symmetrically, where both relevant costs and relevant benefits are included in the screening analysis. For example, a state that chooses to include participant costs in its screening test should also include participant benefits, including non-energy benefits, otherwise the test will be skewed against energy efficiency resources.
- Hard-to-Quantify Benefits. Efficiency screening practices should not exclude relevant benefits on the grounds that they are difficult to quantify and monetize. Several methods are available to approximate the magnitude of relevant benefits, as described below.
- Transparency. Efficiency program administrators should use a standard template to explicitly identify their state's energy policy goals and to document their assumptions and methodologies.
- Applicability to all resources. In general, these principles should be applied to all types of electric and gas utility resources; both demand-side and supply-side resources.

Q. Does the NESP Recommendations document provide any guidance on how the standard screening tests should be defined?

A. Yes. While all states use one or more of the standard "tests" described in the California Standard Practice Manual as the foundation for their own efficiency screening practices, states differ in their definitions of these tests. Figure 3.1 presents the definitions of the standard screening tests, based on the most recent literature on this topic and the NESP recommendations. I will return to Figure 3.1 when I discuss the Utilities' definitions of cost-effectiveness below.

Figure 3.1. Components of the Standard Cost-Effectiveness Tests

	Participant Test	RIM Test	Utility Test	TRC Test	Societal Test
Energy Efficiency Program Benefits:					
Customer Bill Savings	Yes	---	---	---	---
Avoided Energy Costs	---	Yes	Yes	Yes	Yes
Avoided Capacity Costs	---	Yes	Yes	Yes	Yes
Avoided Transmission and Distribution Costs	---	Yes	Yes	Yes	Yes
Wholesale Market Price Suppression Effects	---	Yes	Yes	Yes	Yes
Avoided Cost of Environmental Compliance	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (utility perspective)	---	Yes	Yes	Yes	Yes
Non-Energy Benefits (participant perspective)	Yes	---	---	Yes	Yes
Non-Energy Benefits (societal perspective)	---	---	---	---	Yes
Energy Efficiency Program Costs:					
Program Administrator Costs	---	Yes	Yes	Yes	Yes
EE Measure Cost: Program Financial Incentive	---	Yes	Yes	Yes	Yes
EE Measure Cost: Participant Contribution	Yes	---	---	Yes	Yes
Lost Revenues Associated with Fixed Costs	---	Yes	---	---	---

Q. Is the Resource Value Framework a new screening test for states to consider?

A. No. It is a framework—a set of principles and recommendations—that provides guidance for each state in designing and implementing its energy efficiency screening process. The Resource Value Framework is designed to provide each state with flexibility to ensure that its screening practices meet its own needs and interests.

One of the key concepts in the RVF is that states do not need to be confined to the strict definition of the standard screening tests described in the California Standard Practice Manual. The RVF includes the key principles that each state should incorporate into its efficiency screening practices to ensure consistency between its energy efficiency programs and energy policy goals. In other words, each state's screening test should be based on its own legislation, regulations and commission orders. While this may seem like an obvious recommendation, some states apply efficiency screening tests that are not consistent with their own regulatory standards and energy policy goals. In fact, this is one of the fundamental problems with the Utilities' DSM screening practices—they conflict with FEECA standards and policy goals.

Q. Does the NESP Recommendations document provide any guidance on efficiency screening tests that should not be used?

A. Yes, the NESP Recommendations document clearly recommends against the RIM test's use for screening energy efficiency programs, for reasons that I will describe below. Instead, states should use other analyses, and apply other considerations to address concerns about rate impacts from energy efficiency programs. Florida is no exception.

Q. Based on your work with the National Efficiency Screening Project, what lessons does it offer to Florida?

A. Contrary to perhaps the most fundamental NESP recommendation, the Utilities try to define cost-effectiveness and conduct resource screening in ways that conflict with FEECA and the related Commission regulations and decision-making precedents.

Another key NESP recommendation is that the RIM test should not be used for screening DSM measures. Contrary to this recommendation, the Utilities rely almost entirely on the RIM test in their definitions of cost-effectiveness, and in their resource planning process.

Another key NESP recommendation is that a utility's DSM screening assumptions, methodologies and practices should be transparent, so that regulators and other stakeholders can draw meaningful conclusions from them. The Utilities resource planning process is anything but transparent; it is convoluted, overly-complex, not well explained, and lacking in the information that the Commission ultimately needs to set DSM goals. To make matters worse, the Utilities present the results of their resource planning analyses in ways that are unnecessarily confusing and even misleading.

In sum, the Utilities' DSM screening practices are out of synch with standard industry practices, and do not even come close to meeting evolving industry "best practices." I elaborate on all of these points below.

The Definition of Cost-Effectiveness in Florida

Q. How is DSM cost-effectiveness defined in FEECA?

A. The Florida Energy Efficiency and Conservation Act focuses on cost-effectiveness, starting with the very first sentence in the Act, which states: "[t]he Legislature finds and declares that it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. This language is especially important in this goal-setting docket, not only because it requires that demand-side conservation systems (i.e., DSM programs) be cost-effective, but also because it places the concept of cost-effectiveness in the context of protecting the health, prosperity and general welfare of the state and its citizens.

FEECA provides further guidance on how to assess cost-effectiveness. Section 366.82(3), F.S., states that in developing DSM goals the Commission shall take into consideration:

a) The costs and benefits to customers participating in the measure.

b) The costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions.

c) The need for incentives to promote both customer-owned and utility-owned DSM and demand-side renewable energy systems.

d) The costs imposed by state and federal regulations on the emissions of greenhouse gases.

Q. How is DSM cost-effectiveness defined in the Commission's regulations?

A. Rule 25-17.008, F.A.C., sets out in detail the methodologies and tests for estimating efficiency program cost-effectiveness. In particular, the Rule identifies the minimum filing requirements for utilities reporting cost-effectiveness data, and the Rule refers to the Commission's Cost-Effectiveness Manual.[8] That Manual requires that cost-effectiveness analyses be conducted using three tests: the Participants test, the RIM test, and the Total Resource Cost (TRC) test.

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[8] Florida Public Service Commission, *Cost-Effectiveness Manual For Demand-Side Management Programs and Self-Service Wheeling Proposals,* July 17, 1991.

In its FEECA Annual Report, the Commission provides the following definitions of these DSM cost-effectiveness tests:

- Participants test. The Participants test analyzes costs and benefits from a program participant's point of view and ignores the impact on the utility and other ratepayers not participating in the program. The costs customers pay for equipment and maintenance are considered under the Participants test. Benefits considered in the test include incentives that are paid by the utility to the customers and a reduction in customer bills.
- RIM test. The RIM test includes the costs associated with incentive payments to participants and decreased revenues to the utility which typically must be recovered from the general body of ratepayers at the time of a rate case. In particular, the RIM test is designed to ensure that all ratepayers, not just the program's participants, will benefit from a proposed DSM program. A DSM program that passes the RIM test ensures that all customer rates are lower than they otherwise would have been without the DSM program.
- TRC test. The TRC test measures the overall economic efficiency of a DSM program from a social perspective. This test measures the net costs of a DSM program based on its total costs, including both the participant's and the utility's costs. Unlike the RIM test, customer incentives and decreased revenues are not included as costs in the TRC test; instead, these factors are treated as transfer payments among ratepayers. Moreover, certain external costs and benefits such as environmental impacts are appropriate for inclusion under the TRC test.

FPSC, *Annual Report on Activities Pursuant to the Florida Energy Efficiency and Conservation Act*, (Feb. 2014), at 15, *available at* http://www.psc.state.fl.us/publications /pdf/electricgas/FEECA2014.pdf ("2014 FEECA Report").

Q. How did the Commission address DSM cost-effectiveness in the last DSM goal-setting case?

A. The Commission found that the TRC test (or, the e-TRC test) should be used to set DSM goals, and that consideration should be given to the impacts—especially the rate impacts—of efficiency programs on non-participants. In particular, the Commission found that:

> . . . consideration of both the RIM and TRC tests is necessary to fulfill the requirements of Section 366.82(3)(b), F.S. Both RIM and TRC tests address costs and benefits beyond those associated solely with the program participant. By having RIM and TRC results, we can evaluate the most cost-effective way to balance the goals of deferring capacity and capturing energy savings while minimizing rate impacts to all customers.

Order No. PSC-09-0855-FOF-EG, at 15. The utilities proposed DSM goals that were based on the E-RIM test, which is an enhanced version of the RIM test including avoided carbon compliance costs. The Commission rejected this approach and approved DSM goals based upon the unconstrained E-TRC test, which is an enhanced version of the TRC test including avoided carbon compliance costs. *Id*.

With regard to rate impact considerations, the Commission found that:

> Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in the monthly utility bill. Since participation in DSM programs is voluntary and this Commission is unable to control the amount of electricity each household consumes, we should ensure the lowest possible overall rates to meet the needs of all customers.

Id. at 26.

Q. How has the Commission addressed DSM cost-effectiveness issues in more recent orders?

A. After the Commission set the 2009 DSM goals, the Utilities' filed DSM Plans that described their proposals to meet those goals. The Commission approved the proposed DSM Plans of TECO, JEA, Orlando Utilities Commission (OUC) and Florida Public

Utilities Company (FPUC) in 2010, and the proposed DSM Plan of Gulf in 2011. *See* 2014 FEECA Report, at 17-18 (citing relevant orders).

However, the Commission modified the proposed DSM Plans proposed by FPL and DEF. The Commission found that their proposed DSM Plans would result in an increase to the average residential customer's monthly bill that would "constitute an undue rate impact on customers." Order No. PSC-11-0346-PAA-EG, at p. 4 (FPL); Order No. PSC-11-0347-PAA-EG, at 5, 6 (DEF, then Progress Energy Florida, Inc.). Consequently, the Commission directed FPL and DEF to modify their DSM plans to continue their existing programs, finding that the rate impacts of those programs were "relatively minor." Order No. PSC-11-0346-PAA-EG, at 5; Order No. PSC-11-0347-PAA-EG, at 7.

<u>The Utilities' Definition of Cost-Effectiveness</u>

Q. How have the Utilities defined cost-effectiveness?

A. FPL uses four tests in its preliminary screening of DSM: the Participants test; the preliminary RIM test, the preliminary TRC test; and the "years-to-payback test, using a two-year criterion. Direct Testimony of Witness Sim, Document No. 01476-14, at 23. DEF uses the Participant, TRC, and the RIM tests in its preliminary screening of DSM. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 27.

However, both FPL and DEF ultimately use the RIM test in determining their DSM goals.

Q. Please summarize your concerns with the Utilities' definitions of cost-effectiveness.

A. I summarize several concerns here, and address each of them in more detail in the following subsections.

First and foremost, the Utilities' definitions are not in compliance with either the overall intent of FEECA or the specific requirements of FEECA. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. The Utilities' cost-effectiveness analyses do not meet this overall goal. FEECA also requires that in establishing the DSM goals, the

Commission should take into consideration "the costs and benefits to customers participating in the measure" and "the costs and benefits to the general body of ratepayers as a whole, including utility incentives and participant contributions." Section 366.82(3), F.S. Again, the Utilities definition of cost-effectiveness does not comply with this requirement.

Second, the Utilities ultimately only rely on one test to propose goals: the RIM test. Despite the appearance of modeling and analyzing several different tests, they use the RIM test as the sole criterion for making the final decision in setting DSM goals. The RIM Test should never be used to determine DSM cost-effectiveness; there are better ways to address the important issue of DSM rate impacts.

Third, the Utilities use incorrect methodologies and assumptions for estimating the lost revenues from DSM programs. Consequently, their estimates of lost revenues —the key additional cost included in the RIM test—are significantly overstated. Furthermore, the Utilities present the results of the RIM Test in misleading ways, dramatically overstating the extent to which customers will experience higher rates.

Fourth, the Utilities misrepresent (or misunderstand) the proper definition of the TRC test, by asserting that this test does not account for the incentive payments that the utility provides to the participating customer. Accordingly, they have incorrectly dismissed the TRC test as not in compliance with FEECA, when in fact it is the one test that is most in compliance with FEECA.

Fifth, the Utilities ignore one of the most useful screening tests available: the Utility Cost test. This test is especially helpful for determining the economic impact on all customers as a whole, and for providing useful information regarding rate and bill impacts.

Sixth, the Utilities do not properly account for the cost of complying with greenhouse gas (GHG) regulations, as required by FEECA in Section 366.82(3)(d), F.S. They also do not account for non-energy benefits of DSM. Consequently, their analyses significantly understate the benefits of DSM, both to participants and non-participants.

Finally, the Utilities apply fundamentally flawed resource planning practices to further analyze the potential role of DSM programs in meeting resource planning needs. This exacerbates and adds to the problems outlined above. I address these problems in more detail in Section 4.

In sum, the Utilities' misuse of DSM cost-effectiveness tests, combined with their flawed efficiency screening process, lead to results that are so defective as to make them meaningless. The Utilities' analyses ultimately obscure the basic fundamental fact that DSM programs offer tremendous benefits to customers because they cost significantly less than supply-side alternatives. I offer some alternative economic analysis in Section 5 to expand upon and clarify this critical point.

The Rate Impact Measure Test Can Lead to Perverse Outcomes

Q. Why do you recommend that the RIM test not be used to evaluate DSM cost-effectiveness?

A. The RIM test should never be used for evaluating DSM cost-effectiveness both on theoretical grounds and for practical reasons. In sum, the logic underlying the RIM test is flawed; it will not result in lowest costs to the utility system or to the utility customer; it can lead to perverse outcomes where significant cost reductions are foregone in order to avoid negligible rate impacts; it is inconsistent with the regulatory treatment of supply-side resources; and (worst of all) it provides no meaningful information for the Utilities or the Commission to use in addressing the key issue of rate and bill impacts.

Q. Why do you say that the underlying logic of the RIM test is flawed?

A. The only difference between the RIM test and the Utility Cost test is the "lost revenues," (i.e., the reduction in the revenues as a result of reduced consumption). If the utility is to be made financially neutral to the impacts of the DSM programs, then the utility should collect that portion of the lost revenues necessary to recover its fixed costs (because fixed costs are not reduced as a result of DSM). If the utility were to recover these lost revenues in rates, then they would result in rate increases.

To understand this issue it is critical to recognize that these lost revenues are the primary reason that long-term rates increase as a result of DSM programs. If it were not for these lost revenues, then DSM programs would generally cause long-term rates to be *lower than they would be otherwise*, because the benefits of cost-effectiveness DSM outweigh the costs.

It is also critical to recognize that lost revenues are not a "new" cost created by the DSM programs. Lost revenues are simply a result of the need to recover *existing costs spread out over fewer sales*. The existing costs that might be recovered through rate increases as a result of lost revenues are (a) not caused by the efficiency program themselves, and (b) are not a new, incremental cost. In economic terms, these existing costs are called "sunk" costs. Sunk costs should not be used to assess future resource investments because they are incurred regardless of whether the future project is undertaken. Application of the RIM test is a violation of this important micro-economic principle.

Q. Why do you say that the RIM test will not result in the lowest cost to the utility system or customers?

A. Applying the RIM test to screen efficiency programs will not result in the lowest cost to customers. Instead, it may lead to the lowest rates (all else being equal, and if the test is applied properly). However, achieving the lowest rates is not the primary or sole goal of utility planning and regulation; there are many goals that utilities and regulators must balance in planning the electricity system. Maintaining low utility system costs, and therefore low customer bills on average, should be given priority over minimizing rates. For customers, the size of the electricity bills that they must pay is more important than the rates underlying those bills.

Q. Why do you say that strict application of the RIM test can lead to perverse outcomes?

A. A strict application of the RIM test can result in the rejection of *significant* reductions in utility system costs to avoid what may be *insignificant* impacts on customers' rates. In fact, this is the outcome of the DEF and FPL reliance on the RIM test to propose DSM goals. As I demonstrate in Section 4, the magnitude of rate impacts that are likely to result from the Utilities' DSM goals are so small as to be unnoticeable, and yet the Utilities use the concept of rate impacts to reject large amounts of DSM measures that could save customers millions, perhaps billions of dollars. Such a result is clearly not in the best interests of customers overall.

Q. Why do you say that applying the RIM test is inconsistent with the regulatory treatment of supply-side resources?

A. The main goal of the RIM test is to avoid cross-subsidies between customers. In theory, DSM program non-participants may subsidize participants, because the participants may experience reduced bills as a result of reduced electricity consumption, while non-participants may experience increased bills as a result of increased rates. The Utilities claim many times over that they should use their resource planning process to minimize rate impacts, because this will then avoid cross-subsidization. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 26-28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 7, 15.

While it is important to avoid cross-subsidies where possible, it is also important to recognize that cross-subsidies are endemic to regulated electric utilities. For example:

- When a utility installs a new power plant to meet increasing electricity demands, customers whose electricity demands have not increased in recent years subsidize those customers whose demands have increased.
- When a utility installs a new transmission line to maintain or improve reliability in one part of its service territory, all customers are required to pay for the new transmission line, even though many customers do not experience its benefits.
- When a utility installs distribution systems to serve a newly-developed residential neighborhood or a new industrial park, all customers are required to pay for the new distribution systems, even though many customers do not experience the benefits of them.
- Customers within a rate class that have a high load factor (i.e., high energy consumption relative to peak demand), will subsidize customers in that same rate class with a low load factor, because the cost of power is so much greater during times of peak demand.

Accordingly, DSM should not be held to a standard that cross-subsidization will not be allowed, when that same standard is not applied to supply-side resources. This is especially true given that doing so can lead to perverse outcomes, as described immediately above.

Q. Why do you say that the RIM test provides no meaningful information for addressing the issue of rate and bill impacts?

The RIM test does not provide any information about what actually happens to rates as a result of program implementation. A RIM test benefit-cost ratio of less than one indicates that rates will increase (all else being equal), but says little to nothing about the magnitude of the rate impact, in terms of the percent (or ¢/kWh) increase in rates or the percent (or dollar) increase in bills. In other words, the RIM test results do not provide any context for utilities and regulators to consider the magnitude and implications of the rate impacts. What are the implications of DSM plan with a RIM Test benefit-cost ratio of 0.98? How about a benefit-cost ratio of 0.87? How much are customers harmed by these results relative to a positive RIM benefit-cost ratio of 1.2? The RIM Test cannot answer such important questions.

Even worse, the RIM test results can be very misleading. When the RIM test results are put in terms of negative net benefits (the net benefits will be negative for DSM programs that fail the RIM test), it appears as though the DSM programs will be *increasing* costs to customers. However, as described above, the costs that drive the rate impacts under the RIM test are not new, incremental costs associated with the DSM programs. They are *existing costs*, existing fixed costs to be more precise. These are the existing costs that are already in electricity rates. Any rate increase from lost revenues would be a result of recovering those existing fixed costs over fewer sales; not as a result of incurring new costs. In fact, the Utilities present their RIM test results in this misleading way. For example, FPL states that it would have to incur “an additional cost of approximately $296,000,000 in 2015, or of approximately $630,000,000 in 2014” to raise rates enough to cover the TRC 337 MW plan relative to the RIM 337 MW plan. Direct Testimony of Witness SIM, Document No. 01476-14, at 58. This simply is not true. The recovery of lost revenues does not result in “additional” costs to the utility or to customers. Lost revenues are recovered to help the utility pay for existing fixed costs.

Finally, the RIM test does not provide the specific information that utilities and regulators need to assess the actual rate and bill impacts of DSM programs. Such information includes the impacts of DSM on long-term average rates, the impacts on average customer bills, and the extent to which customers participate in efficiency programs and thereby experience lower bills.

Q. Are these concerns about the RIM test recognized by other states and other regulatory commissions?

Yes, essentially every state in the country has rejected the use of the RIM test as the primary test to use for determining DSM cost-effectiveness. The Commission should not set efficiency goals based on the outcome of the Utilities’ analyses, which are directly in conflict with standard industry practice throughout the US.

Q. So far, you have shown why the RIM test generally should not be used in any state for screening DSM programs. Do you have any particular concerns with the way that the RIM test is calculated and applied by the Utilities in Florida?

A. Yes. The Utilities’s methodology significantly overstates the magnitude of the lost revenues, and as a consequence significantly overstates the rate impacts of their DSM proposals. This occurs in two ways.

First, the Utilities use an incorrect methodology for estimating the magnitude of the lost revenues that will impact rates. The Utilities estimate lost revenues on the basis of a projection of total electricity prices. *See*, *e.g*., Direct Testimony of Witness Guthrie, Document No. 01497-14, at 38. This is not the correct methodology for estimating lost revenues that will impact rates. The correct methodology is to use a projection of the *fixed components of rates*, not the fixed plus variable components of rates. It is necessary to separate out the portion of rates that represent variable costs, because utilities will be able to reduce variable costs through DSM and therefore will not need to recover any lost revenues associated with those variable costs. The Utilities’ assumption that lost revenues should be based on the total electricity rates (fixed and variable components) implies that they will somehow be allowed to increase customer rates for *variable costs that they do* *not incur*. That is clearly not how rates are set in Florida, or any state, and should not be the assumption underlying estimates of DSM rate impacts.

Second, the Utilities' methodology for estimating rate impacts is inconsistent with the way that rates are set in Florida. Base rates are only increased at the time of a rate case. Between rate cases, *DSM will not increase rates* because the Utilities' rates will not be adjusted to collect lost revenues of any kind. Eventually with the next rate case, rates will be adjusted based on the most recent sales levels, including savings from DSM up to that point in time. However, the lost revenues that may occur between rate cases are not recovered by the utility, even at the next rate case. For this reason alone, the RIM test results provided by the Utilities are simply wrong—they significantly overstate the extent to which the Florida DSM programs might increase rates.

Each of the two reasons that I just described renders the Utilities' estimates of rate impacts fatally flawed and essentially useless for setting DSM goals. Therefore, I recommend that the Commission completely reject the Utilities' rate impact estimates when setting DSM goals.

Q. Do the Utilities claim that application of the RIM test is consistent with FEECA?

A. Yes. FPL and DEF claim that the Participants test and the RIM test should be used for screening DSM. *See*, *e.g*., Direct Testimony of Witness Sim, Document No. 01476-14, at 28; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15 ("these two tests capture all of the relevant costs and benefits that should be evaluated when considering an efficiency or load reduction program."). However, the RIM test is much more stringent than the Participants test, and therefore if the two tests are applied together, then the RIM test will be the deciding factor on cost-effectiveness.

Further, FPL proffers that the TRC test "omits the incentive payments made to program participants." *Id*. at 26-27. Based on FPL's misunderstanding that the TRC test omits these incentive payments, FPL essentially rejects the use of the TRC test for screening purposes. Finally, FPL ignores other cost-effectiveness tests that could meet FEECA standards and policy goals.

Q. Do you agree with the Utilities' characterization of these tests?

A. No. The Utilities misinterpret FEECA requirements, and screening test-definitions and implications. Consequently, the Utilities' methodology conflicts with FEECA.

First, the RIM test does not indicate the "cost" impacts on the utility and its customers. As discussed above, it indicates the potential rate impacts on the utility customers (although a not a very useful indication). The distinctive component of the RIM test is the lost revenues, which are not costs associated with DSM. Lost revenues can potentially lead to rate impacts, but they are not cost impacts.

It is important to note that FEECA does not in any way require the minimization of rates as a criterion for setting DSM goals. FEECA is clear about the intent to reduce costs, but does not mention minimization of rates at all.

Second, the Utilities have misinterpreted the definition of the TRC test. FPL and DEF try to argue that the TRC test does not include the incentive payments made to program participants. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 27; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 15-16. In fact, the TRC test does, or should, include these customer incentive payments. The purpose of the TRC test is to include all costs associated with a DSM measure, regardless of who pays them. That is why it is called the "Total Resource Cost" test. Note in Figure 3.1 above, that the customer incentive payment should be included in the TRC test. This is standard industry practice.[9]

In sum, the Utilities rely on a misunderstanding of the definition of the TRC test to reject this test for the purpose of screening DSM measures. However, the TRC test is in fact the best test to indicate the "costs and benefits to the general body of ratepayers as a whole,

[9] It appears as though the Commission is inconsistent on the definition of the TRC test. The 2014 FEECA Report states that the TRC test measures a "DSM program based on its total costs, including both the participant's and the utility's costs." In the next sentence, however, Report states that customer incentives are not included in the TRC test, instead they are treated as "transfer payments" among ratepayers. 2014 FEECA Report, at 15. These two sentences are inconsistent. The first point, about including both the participant's and the utility's costs is the correct definition of the TRC test.

including utility incentives and customer contributions," as required by FEECA. Section 366.82 (3)(b), F.S.

Q. Has the Commission the authority to consider the rate impacts of DSM goals?

A. Yes. Commissions generally have wide discretion to consider many aspects of rates, in many contexts. In previous DSM goal-setting docket, the Commission noted that:

> As specified in Section 366.01, F.S., the regulation of public utilities is declared to be in the public interest. Chapter 366 is to be liberally construed for the protection of the public welfare. Several sections within the Chapter, specifically, Sections 366.03, 366.04, and 366.05, F.S., refer to the powers of the Commission and setting rates that are fair, just and reasonable. The 2008 legislative changes to FEECA did not change our responsibility to set such rates.

Order No. PSC-09-0855-FOF-EG at 25.The concept of setting rates that are "fair, just and reasonable" is widely used in the regulation of the electricity industry. Notably, this standard makes no reference to rate minimization. Rates should be fair, just and reasonable. This requires consideration of, and often a balancing among, several factors beyond rates alone.

Q. Should the Commission consider rate and bill impacts when setting DSM goals?

A. If the rate impacts of DSM goals are of concern, then, yes the Commission should consider implications of rate and bill impacts. However, the RIM test should not be used for this purpose, for the reasons provided above. Instead, rate and bill impacts should be considered using comprehensive, meaningful analyses that provide the utilities and Commissioners with the information necessary to strike the appropriate balance between reduced bills and increased rates. I offer some recommendations on this point in the following subsection.

<u>Rate and Bill Impacts Should be Assessed in Other Ways</u>

Q. How should the Utilities address rate and bill impacts from DSM programs?

A. It is important to recognize that the primary challenge facing the Commission in setting DSM goals is in striking the proper balance between reduced costs and the potential for increased rates. FEECA is clear that the Commission should seek to establish DSM goals that will reduce costs to the "general body of ratepayers as a whole." Section 366.82(3)(b), F.S. This suggests an emphasis on reduced costs, because ratepayers on average will be better off with reduced costs and reduced bills. In addition, FEECA provides the Commission with the authority to "modify or deny plans that would have an undue impact on the costs passed on to customers." Section 366.82(7), F.S. This language also emphasizes costs over rates.

Nonetheless, the Commission always has the responsibility to consider rate impacts in resource decision-making, and to prevent "undue" rate impacts on customers. Taken together, these considerations indicate that the Commission should not set DSM goals based on rate impacts alone, but should instead strike the proper balance between reduced costs and the potential for increased rates.

Q. What kind of considerations help strike a balance between reduced costs and the potential to increase rates?

A. Three considerations are the most helpful: rate impacts, bill impacts, and DSM program participation rates. Rate impacts, properly estimated, provide an indication of the extent to which rates might increase due to DSM. Bill impacts, properly estimated, provide an indication of the extent to which average customer bills might be reduced due to DSM. Participation rates, properly estimated, provide an indication of the extent to which customers will experience bill reductions or bill increases. Taken together, these three measures indicate the extent to which customers as a whole will benefit from DSM.

Q. How should rate impacts be estimated?

A. Rate impact estimates should account for all factors that impact rates, either positively or negatively. This would include all avoided costs that might exert downward pressure on rates (e.g., generation, transmission, and distribution), including the avoided costs of complying with environmental regulations. Any estimates of the impact of lost revenue recovery on rates should (a) only reflect collection of lost revenues necessary to recover fixed costs, and (b) only reflect the actual impact on rates according the Florida ratemaking practices. Rate impacts should be estimated over the long-term, to capture the full period of time over which the efficiency savings will occur. Rate impacts should also be put into terms that place them in a meaningful context; e.g., in terms of ¢/kWh or percent of total rates.

Q. How should bill impacts be estimated?

A. The bill impacts should build upon the estimates of rate impacts described above. The rate impacts apply to every customer (within the rate class analyzed). Bill impacts, on the other hand, will vary between customers depending upon whether they participate in the DSM programs, and depending upon which DSM program they participate in. Therefore, bill impacts should be estimated separately for each of the types of DSM programs. As with rate impacts, they should be estimated over the long-term, and they should be put into terms that place them in a meaningful context; e.g., in terms of dollars per month, or percent of total bills.

Q. How should program participation rates be estimated?

A. Program participation rates should be estimated by dividing the program participants by the total population of eligible customers, to get a rate in percentage terms. This should be done for each year, and for each program. Participation rates should be compiled across several years to indicate the extent to which customers are participating in the programs over time. To the extent possible, participation in multiple programs and across multiple years should be captured. The long-term program participation rates can be compared with the long-term bill impacts and the long-term rate impacts to get a sense of the extent to which customers are benefiting from the DSM programs.

Q. You recommended that the level of program participation should be considered when deciding whether specific rate impacts are acceptable. Please elaborate on why the level of program participation should be considered when assessing rate impacts of DSM programs.

A. Rate impacts primarily raise the issue of customer equity. Therefore, to assess whether rate impacts—and more importantly, bill impacts—are acceptable and yield equitable outcomes, customer participation rates must be considered. Specifically, program participation rates can reveal the extent to which customers experience bill increases or decreases. If a large portion of customers participate in DSM programs, then the Commission and other stakeholders should be willing to accept relatively higher rate impacts because many customers will experience net bill reductions and few customers will experience bill increases.

Furthermore, this type of participation information can be very important in reviewing and assessing the Utilities' DSM programs in general. It provides an indication of how successfully each program is pursuing customers, as well as an indication of which types of customers could benefit from future efficiency programs.

Q. Are there actions that the Commission and Utilities can take to increase customer participation in the DSM programs, and thereby mitigate customer equity concerns?

A. Yes. First, the DSM program goals and budgets can be set in a way to increase customer participation. Energy efficiency program goals and budgets could be increased to grow the number of customers that experience bill reductions. This is the exact opposite of approach proffered by the Utilities, which is to reduce DSM program goals and budgets to minimize rate impacts. *In my view, customers overall are better served by a broader application of well-designed, cost-effective DSM programs, because such programs reduce energy system costs and reduce customer bills.*

Q. Is there another approach that the Commission and Utilities can take to maximize customer participation in the DSM programs?

A. Yes. The DSM programs can be designed in a way that encourages as much participation as possible, across as broad a variety of customer types as possible. In particular, DSM programs can be designed to:

- promote all types of efficiency measures that offer cost-effective savings;
- provide all customer types with an opportunity to participate, including hard-to-reach customers such as low-income customers;
- offer efficiency measures that are specifically tailored to many different customer types;
- provide financial and other incentives to overcome the market barriers that prevent customers from participating; and

- identify, target and actively pursue non-participants.

Programs that incorporate these design principles will be more likely to reach a large number of customers, and eventually increase program participation.

Q. Do non-participants experience any benefits of DSM programs?

A. All customers experience the benefits—regardless of whether they participate in the programs. Energy efficiency provides benefits to the entire electricity system, and these benefits are shared by all customers. In particular, DSM can improve system reliability, reduce the need for new generation capacity, reduce planning risk, reduce transmission and distribution costs, reduce the costs of complying with environmental mandates, and reduce reliance upon fossil fuels. Efficiency also results in societal benefits such as local job growth and economic development, reduced environmental impacts and increased economic development. FEECA recognizes this when stating that the Act's intent is to "protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S.

My main point is that concerns about rate impacts are rooted in customer equity issues between participants and non-participants because participants experience direct benefits from DSM (i.e., reduced bills from reduced consumption) that non-participants do not experience. Therefore, when addressing rate impact issues, it is important to fully understand and address this customer equity issue.

<u>The Utilities Do Not Account for the Cost of GHG Regulations</u>

Q. Does FEECA require the Commission to consider the costs of compliance with greenhouse gas regulations?

A. Yes. FEECA requires the Commission to consider, among other things, the "cost imposed by state and federal regulations on the emission of greenhouse gases." Section 366.82(3)(d), F.S.

Q. How should the various efficiency screening tests account for GHG regulatory compliance costs?

A. The cost of complying with current and expected GHG regulations should be included in the TRC test, the Utility Cost test, the Societal Cost test, and in any analyses of rate and bill impacts. The cost of compliance with any environmental requirements is a cost that will be incurred by utilities and passed on to electricity customers through electricity rates. This compliance cost is therefore an electric system cost, and reducing that cost through DSM is an electricity system benefit. All electricity system costs and benefits should be included in the Utility Cost test, the TRC test, the Societal Cost test, and any analyses of rate and bill impacts.

Note that the cost of complying with environmental regulations are not the same as environmental damage costs (e.g., reduced air quality, damages to lakes and forests, public health impacts). The cost of complying with environmental regulations are an electricity system cost that will be passed on to customers. Environmental damage costs are born by society at large, but do not affect electricity costs or electricity rates.

Q. Why is it so important to account for the cost of compliance with environmental regulations when screening DSM programs?

A. Energy efficiency resources are the most widely available and the lowest-cost option to reduce greenhouse gas pollution and other air pollution. It is important that these low-cost resources be fully utilized to comply with current and future environmental regulations. Otherwise, the costs of complying with such regulations will be greater, and electricity customers will end up paying higher costs than necessary.

Furthermore, DSM offers a set of policy options for reducing GHG pollution that result in *lower bills* for customers, by reducing customer electricity consumption levels. Other GHG pollution reduction options typically result in higher bills for customers.

In sum, it is important to properly account for environmental compliance costs when screening DSM programs because this will minimize future costs to electricity customers.

Q. How should the Utilities account for GHG regulatory compliance costs?

A. The Utilities should apply the best estimate available of the likely costs of complying with state and federal requirements for controlling greenhouse gas pollution during the entire DSM cost-effectiveness study period. Doing so is common practice in the electricity industry. At least 28 utilities have recently used a forecast of CO_2 costs in their planning practices, including utilities in: Arkansas, Arizona, California, Connecticut, Hawaii, Louisiana, Maine, Massachusetts, Mississippi, South Carolina, New Hampshire, New Mexico, Nevada, North Carolina, Tennessee, Idaho, Indiana, Oklahoma, Oregon, Utah, Vermont, Washington.[10]

Q. How do DEF and FPL account for the cost of complying with GHG regulations when screening efficiency and setting goals?

A. As a part of their resource planning, DEF and FPL have conducted sensitivity analyses where they include CO_2 cost estimates. Both DEF and FPL proffer that adding the CO_2 costs hardly changes the amount of economic or achievable DSM potential, and thus hardly impacts efficiency opportunities or their DSM goals. *See*, *e.g.*, Direct Testimony of Witness Sim, Document No. 01476-14, at 45-46; Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibit HG-14.

Q. Do you agree with FPL's and DEF's conclusion that the cost of complying with GHG regulations will have little impact on their efficiency opportunities?

A. No. This conclusion is counter-intuitive, and highlights just how constraining FPL's and DEF's screening process is. As described in Section 4, FPL's and DEF's resource screening practice suffers from so many flaws and limitations that the results cannot be trusted. Furthermore, FPL's and DEF's resource screening eliminated the majority of DSM measures before CO_2 costs were even considered in the sensitivity analyses. Therefore, I recommend that the Commission give no weight to the results of FPL's and DEF's CO2 sensitivity analyses.

Q. How would the proper accounting of GHG regulatory compliance costs impact the Utilities' cost-effectiveness analyses?

A. The impact would be significant for several reasons. First, properly accounting for GHG regulatory compliance costs would increase the number of DSM measures included in the economic potential and the achievable potential. For example, the consideration of carbon costs was "the primary driver behind why Tampa Electric's energy [GWh] goals

[10] Synapse Energy Economics, *2013 Carbon Dioxide Price Forecast*, November 2013, p. 17.

increased over 70 percent" in the last round of goal-setting. *See*, Witness Bryant Deposition Transcript, Hearing Exhibit 4, Item 7, Docket Nos. 080407–080413, at 89.

Second, properly accounting for the value of avoiding GHG compliance costs would decrease the estimated rate impacts of DSM. As described above, complying with an environmental regulation is a cost to the utility system. For any given level of efficiency savings, proper treatment of the value of avoiding GHG compliance costs would indicate lower utility system costs, which would in turn indicate lower rate impacts. In other words, by failing to correctly account for avoided GHG compliance costs in their resource planning, the Utilities omit one of the benefits of DSM that should be included in the RIM test, and thus overstate the rate impacts.

The Utilities Ignore Non-Energy Benefits of Energy Efficiency

Q. What are non-energy benefits of DSM programs?

A. Non-energy benefits are those costs and benefits that are not part of the costs, or the avoided costs, of the energy provided by the utility that funds the efficiency program.[11] There is a wide range of non-energy benefits associated with DSM programs. Non-energy benefits are categorized by the perspective of the party that experiences the impact: the utility, the participant, or society at large.

- Utility non-energy benefits are indirect savings to the utility; savings that will reduce revenue requirements and thus benefit all ratepayers. These include, for example, reduced arrears, reduced bad debt, reduced costs associated with customer disconnection and reconnection.

- Participant non-energy benefits are benefits to DSM program participants. These include, for example, reduced O&M costs, increased safety, improved health, improved productivity in schools and businesses, improved aesthetics and comfort, and water savings. Participants can also experience benefits in terms of "other fuel

[11] Synapse Energy Economics, Inc., "Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs," prepared for Regulatory Assistance Project, November 2012, at 3.

savings;" i.e., when gas, oil or other fuels are saved as a result of an electric efficiency program. Participant non-energy benefits can be experienced by all types of customers, but certain non-energy benefits are more significant for low-income programs.

- Societal non-energy benefits are benefits that accrue to society at large, beyond those realized by utilities or program participants. These include, for example, impacts on the environment, economic development, job growth, reduced healthcare costs, and national security benefits.

Q. Are these non-energy benefits relevant to the efficiency screening tests used in Florida?

A. Yes, for three reasons. First, as noted above FEECA requires that utilities implement DSM programs "to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Thus, DSM goals should reflect DSM benefits beyond just those that accrue to the utility system. To do so, non-energy benefits should be included in DSM screening.

Second, as noted above, FEECA requires that in establishing the DSM goals the Commission shall consider "the costs and benefits to customers participating in the measure." Section 366.82(3)(a), F.S. To comply with this directive, participant non-energy benefits should be included in DSM screening.

Third, as indicated in Figure 3.1, participant non-energy benefits are one of the key parts of the TRC test. If these benefits are omitted from the TRC test, then the test will be internally inconsistent and inherently skewed against DSM.

Q. Why would the TRC test be internally inconsistent and skewed against efficiency if participant non-energy benefits are omitted from the TRC test?

A. One of the distinguishing features of the TRC test is that it includes the costs to program participants. When including all participant costs, it is necessary to also include all participant benefits, including both energy benefits and non-energy benefits. Otherwise, the TRC test will include certain costs without considering comparable benefits. This results in a test that is internally inconsistent, and will provide results that are skewed against DSM programs.

Q. Do other states account for participant non-energy benefits in applying the TRC Test?

A. Yes. States that include participant non-energy benefits in their TRC screening use various methodologies and assumptions to estimate the value of participant non-energy benefits. Some states conduct detailed studies to identify these benefits, and to estimate their monetary value so that the estimates can be included in DSM screening. Other states use "a proxy adder" to increase the utility system benefits by a certain percentage amount, as a rough approximation of non-energy benefits. Still other states conduct sensitivity analyses to indicate the extent to which non-energy benefits might influence DSM cost-effectiveness. In recent years, efficiency industry stakeholders have increasingly strived to properly account for participant non-energy benefits.[12]

Q. What about the uncertainty associated with participant non-energy benefits? Are these benefits certain enough to use when screening DSM programs?

A. While there is some uncertainty regarding the magnitude of some participant non-energy benefits, there is no question that they can be quite large, and that they will have a significant impact on DSM cost-effectiveness under the TRC test. There are several ways to address the uncertainties associated with participant non-energy benefits, and it is better to use an informed estimate of non-energy benefits values than to simply assume that they are equal to zero; a number that we know is wrong. Furthermore, it is important to recognize that there is considerable uncertainty regarding many of the assumptions for the future costs and benefits of demand-side and supply-side resources. There is no reason to hold participant non-energy benefits to a higher standard of certainty than these other costs and benefits.

[12] National Efficiency Screening Project, *The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening*, March 2014.

Q. What should the Commission do in this docket to account for participant non-energy benefits?

A. I recommend that the Commission require the Utilities to apply a proxy adder to the efficiency program benefits in the TRC test as an estimate of the participant non-energy benefits. While proxy adders are inherently inexact, it is better to use an informed estimation than to simply assume that the value is zero. Here, I recommend that the Commission require the Utilities to apply the following participant NEB proxy adders: 50 percent for low-income customer programs; 25 percent for residential non-low-income customer programs; and 10 percent for commercial and industrial customer programs. These recommended values are based on my extensive review of non-energy benefits in other states, and are conservative relative to some of the quantified values of non-energy benefits that I am aware of.[13]

If the Commission does not require the Utilities to apply a proxy adder for participant non-energy benefits, the Commission should give less weight to the results of the TRC test and instead give more weight to the results of the Utility Cost test. In the absence of reasonable estimates of participant non-energy benefits, the results of the TRC Test are inherently skewed against DSM, while the Utility Cost Test is not.

At a minimum, the Commission should recognize that TRC results that do not include participant non-energy benefits significantly undervalue the full benefits of the DSM programs. This should at least be a qualitative factor that the Commission considers when setting DSM goals.

[13] Synapse Energy Economics, Inc., *Energy Efficiency Cost-Effectiveness Screening: How to Properly Account for Other Program Impacts and Environmental Compliance Costs*, prepared for Regulatory Assistance Project, November 2012. Synapse Energy Economics, *Best Practices in Energy Efficiency Program Screening: How to Ensure that the Value of Energy Efficiency is Properly Accounted For*, prepared for the National Home Performance Council, July 2012.

4. THE UTILITIES' RESOURCE PLANNING PROCESS

Q. Please provide a summary of the FPL's screening process.

A. FPL provides a relatively detailed description of its screening process, so I will focus on FPL in this Section for this reason. FPL uses a six-step resource planning process to screen DSM and propose DSM goals. Direct Testimony of Witness Sim, Document No. 01476-14, at 15-17, Exhibit SRS-1. To summarize:

- Step 1 develops the DSM Technical Potential. This includes the theoretical full potential for DSM regardless of economic constraints, FPL's resource needs, or customer adoption of efficiency measures. *Id*. at 15.
- Step 2 determines resource needs over the 10-year DSM goal-setting time period. At this point, FPL studies how much capacity (in MW) is needed to meet peak demand requirements, both for a Supply-Only scenario and a With-DSM scenario. *Id*. at 18-22. The results are used in Step 5.
- Step 3 identifies a preliminary DSM Economic Potential via preliminary economic screening that compares DSM options to a single supply-side resource; i.e., without any sort of resource planning analysis. *Id.*at 16. This preliminary economic screening applies the Participants test, the RIM test, the TRC test, and a "years-to-payback" test. *Id.* at 16. At this point, FPL creates two screening "paths." The RIM path analyzes the DSM measures using the RIM test, the Participants Test, and the years-to-payback test. The TRC path analyzes the DSM measures using the TRC test, the Participant test, and the years-to-payback test. *Id*. at 29-30. FPL also conducts several sensitivity analyses, including analyses regarding CO_2 costs, fuel prices, and different levels of years-to-payback. *Id.* at 32-33.
- Step 4 identifies the DSM Achievable Potential. FPL applies an assumption of the "maximum customer incentive level" that it can pay for the DSM measures that passed the economic potential screening above. FPL then estimates the "maximum annual signups" that it could expect from customers based on those customer

incentives. The number of customer signups indicates the extent to which FPL deems DSM savings achievable. *Id*. at 16, 38-39.

- Step 5 develops resource plans (Supply-Only and With-DSM). FPL identifies how many of the DSM measures that passed the Achievable Potential screening above could be used to meet its resource planning needs. The latter only reflect FPL's capacity needs, especially with regard to meeting FPL's 20 percent total reserve margin criterion. *Id.* at 41-42.

- Step 6 analyzes resource plans from both economic and "non-economic" perspectives to select the best resource plan and the accompanying amount of DSM to include in FPL's proposed DSM goals. The economic perspective calculates the levelized system average electric rate for each resource plan. FPL uses this electric rate metric to conduct the economic evaluation of the resource plans and associated amounts of DSM. This metric is also proffered to ensure that there is no cross-subsidization across different groups of customers. *Id*. at 54. The "non-economic" analysis includes two additional "perspectives," including (a) emissions of SO_2, NO_X, and CO_2, and (b) system oil and natural gas usage. *Id*. at 66-67.

Note that the analysis described above is performed for each efficiency measure in isolation. There is no consideration of DSM programs, or the associated technical support, education, marketing, and delivery practices that can be used to implement DSM measures.

Q. Please provide a summary of DEF's resource planning process.

A. DEF performs a resource planning process that is similar to FPL's process. It includes the following key elements:

- DEF conducts a technical potential analysis to identify the amount of DSM and demand-side renewable measures that are theoretically available. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 24.

- DEF conducts a resource planning process, using the Strategist model, to analyze the impacts of DSM from a system resource perspective. DEF develops a Base Case (Supply-Only) plan, and begins economic analysis of DSM measures using the RIM, TRC and Participant tests. *Id*. at 24-27.
- DEF then determines the DSM economic potential, by applying a two-year payback limit for free-ridership, and by performing cost-effectiveness analyses using the RIM and TRC tests. *Id*. at 29-30.
- DEF then sets the DSM achievable potential by applying administrative costs and participant incentives to the economic potential measures. Next, DEF uses a set of "payback acceptance curves" to determine "maximum expected participation rates," and applies a set of "diffusion" curves to determine 10-year participation limits. *Id*. at 31-32.)
- DEF then sets the economic and achievable potentials based on (a) the RIM and Participants tests, and (b) the TRC test. *Id*. at 32-34.
- Finally, DEF conducts sensitivity for fuel prices and free-ridership exclusion periods. *Id*. at 36-37.

Q. Do you have any concerns about the resource planning processes that the FPL and DEF used to set DSM goals?

A. Yes. FPL's and DEF's screening processes suffer from many fundamental flaws. I summarize these flaws below, and elaborate on them in the following subsections.

- The Technical Potential estimates significantly understate the full DSM technical potential in Florida. They exclude many important efficiency measures that are proven to be available, and they continue the Utilities' misguided use of a two-year payback to screen out supposed free-riders.
- FPL and DEF perform two separate economic screening analyses in this process—first, a preliminary screen to determine the economically viable DSM measures, and second, a screen based on resource planning models that supposedly optimize both demand-side and supply-side resources. This results in "double-screening,"

which eliminates a large portion of the DSM measures before they are compared to supply-side resources with the resource planning models.

- FPL and DEF use rate impacts as the primary criterion for resource planning and choosing among resource options. This perpetuates all of the problems with the RIM test that I described above, including the fact that the Utilities' estimates of rate impacts are simply wrong and grossly overstated. Furthermore, FPL's and DEF's own analyses indicate that the rate impacts from the DSM plans that they analyze are likely to be so small as to be unnoticeable.

- FPL incorrectly assumes that DSM can only be implemented if it provides capacity (in terms of MW) that can be used to meet reliability requirements. This ignores DSM's ability to reduce energy costs, and dramatically biases the resource planning process against DSM.

- The FPL's and DEF's resource planning processes do not allow DSM measures the full opportunity to defer new supply-side resources, to reduce the size of new supply-side resources, or to assist with retiring existing, uneconomic supply-side resources. This conflicts with FEECA and gives undue preference to supply-side resources that are "hard-wired" into the system regardless of the amount of DSM savings, including the very expensive and very risky Turkey Point nuclear plant in the case of FPL.

In sum, FPL's and DEF's resource planning processes does not provide the critical information that the Commission needs to set DSM goals pursuant to FEECA. These processes do not provide reasonable estimates of Technical, Economic, or Achievable potential; they do not provide evidence of the extent to which DSM can reduce electricity system costs and therefore reduce customer bills; and they do not provide meaningful information on the extent to which DSM affects the general body of ratepayers as a whole. Ironically, FPL and DEF (erroneously) claim that rate impacts should be the primary criterion for selecting cost-effective DSM, but their own analyses provide almost no useful information that the Commission can use to consider the implications of rate impacts.

<u>The Technical Potential Estimates Understate DSM Potential</u>

Q: What kind of technical potential evaluation does FEECA require?

A: Section 366.82(3), F.S., requires the Commission to "evaluate the full technical potential of all available demand-side and supply-side conservation and efficiency measures." FEECA also requires such evaluation of demand-side renewable energy systems, as discussed in Section 7.

Q: Do you think such an effort is warranted at least every five years?

A: Absolutely. Section 366.82(6), F.S., requires this "full technical potential" evaluation to occur at least every five years, for good reason: Conservation and DSM (together, DSM) are integral parts of a balanced and cost-effective energy system. DSM is particularly valuable in the face of many current challenges for utilities in Florida and many other states, including an over-reliance on generation tied to natural gas (a fuel with notoriously volatile pricing), the need to replace an aging generation fleet, the rising costs and risks of conventional new generation, and the need for transmission and distribution infrastructure upgrades to maintain and expand capacity.

Moreover, rapid changes in the energy sector effectively re-define the regulated energy landscape in intervals even shorter than five years. To meet FEECA's intent to utilize the most efficient and cost-effective DSM programs, the Utilities and the Commission must stay informed of the ongoing research and development regarding these resources, and the potential to include them in Florida's energy system.

Q: Does the evaluation of the full technical potential required by Section 366.82(3), F.S., identify the complete picture of the DSM potential in Florida?

A: No. Technical potential studies by definition do not assess all the implications of DSM. Most importantly, they do not consider the cost-effectiveness of DSM measures; they only measure whether a measure is technically feasible. In addition, they do not consider the likely behavior of customers in response to market changes, pricing signals, and outreach and marketing of efficient products and services. Therefore, to fully capture the potential for DSM in Florida and to best understand the likely costs and benefits to the Utilities' customers, the Commission must also look at the economic and achievable

DSM potential. In fact, the goals proposed by the Utilities are determined by the achievable potential.

Q: Does that mean that the technical potential estimates are irrelevant?

A: No. Each successive estimate of potential is based on the previous one. In other words, the achievable potential is developed based on the results of the economic and technical potential estimates. Therefore, the Commission must verify the completeness and accuracy of every part of the Utilities analysis, from technical potential to achievable potential to the ultimate goal-setting.

Q. Did you review the materials provided by the Utilities regarding their updates of technical DSM potential?

A. Yes, I reviewed the filings by DEF and FPL (Dockets 130199-EI and 130-200-EI, filed on April 2, 2014), as well as their responses to discovery requests by Sierra Club and the Southern Alliance for Clean Energy (SACE). I also reviewed worksheets provided by DEF, FPL, TECO, and Gulf Power that summarize the results of their technical potential updates. These were submitted in advance of the filings as "preliminary drafts" subject to change. I also reviewed a short narrative description of the methodology for updating the 2009 technical potential estimates.

Q. Did you review any other material related to the technical potential estimates?

A. Yes. Because the new estimates are updates of previous estimates from 2009, I also reviewed the potential estimates from the 2009 Technical Potential Study by Itron, Inc. on behalf of the Collaborative comprised of the Utilities (DEF, FPL, TECO, Gulf Power, OUC, and JEA), and the related materials in Dockets No. 080407–080413. In particular, I reviewed critiques of the 2009 Technical Potential Study in Witness Mosenthal's Direct Testimony on behalf of NRDC and SACE, and in Witness Spellman's Direct Testimony on behalf of Staff. Also from those dockets, I reviewed testimony filed by SACE's Witness Wilson and rebuttal testimony filed by Witness Rufo on behalf of the Utilities.

Q. Please summarize the findings of your review of the technical potential.

A. Table 4.1 presents the technical potential by sector as a percentage of sales for that sector, for each of the four utilities named above. These data are drawn from responses provided by the Utilities on December 6, 2013, to SACE's informal data requests dated November 6, 2013.

Table 4.1 Summary of Technical Potential Estimates

	Technical Potential as % of sales			
Utility	Residential	Commercial	Industrial	Total
DEF	44%	24%	15%	33%
FPL	35%	25%	34%	31%
TECO	36%	33%	14%	32%
Gulf	36%	33%	10%	31%

The Utilities' estimates represent a limited estimate of technical potential, in part because they have omitted relevant measures and relevant energy-consuming sectors and end uses from the analysis. These same problems existed in the 2009 Technical Potential Study, as demonstrated by Witness Mosenthal and Witness Spellman in that docket.

Q. What types of measures have been omitted in these estimates of technical potential?

A. The Utilities overlook various measures and market segments. Here I highlight the key omissions, those that are most likely to represent a substantial amount of potential that is omitted from subsequent analysis of the economic and achievable potential. These including building commissioning and retro-commissioning, new types of LED lighting fixtures, various efficiency measures in data centers, efficiency measures for water and wastewater treatment plants and the agricultural sector, and ultra-low energy buildings such as net zero energy buildings and "Passive Houses." I will explain in detail each of these omissions. Also, because the Utilities' discovery responses list dozens of measures in each of the three sectors, and these measure lists appear to be consistent across the Utilities, my observations and recommendations apply to all of the Utilities.

First, the Utilities omit building commissioning and retro-commissioning in the commercial and industrial sectors. These omitted measures involve targeted efforts by building operation experts to identify operational changes and repairs/adjustments to equipment to realize optimum performance. Typically, these savings opportunities are widespread, inexpensive, and result in substantial savings. Witness Mosenthal noted the omission of these measures in his 2009 testimony. *See* Document No. 06794-09, at 11. In rebuttal testimony, Witness Rufo claimed that several of the measures included in the technical potential "represent" the potential associated with retro-commissioning. Document No. 07822-09, at 14 . Yet none of the measures described by Witness Rufo address the operational improvements (rather than equipment-based measures) that are a primary result of retro-commissioning activities. While it may be true that the measures offered by Witness Rufo have some overlap with commissioning and retro-commissioning, his testimony does not substantiate that the full technical potential from these activities are included in the Utilities' estimates and updates.

Second, the Utilities appear to omit new types of efficient lighting fixtures for commercial and industrial applications. For instance, from among the most common type of recessed linear fluorescent lighting, the Utilities only include "LED linear tubes." These products were some of the first of their kind on the commercial marketplace, but they have been rapidly eclipsed in performance by newer fixtures that take advantage of LEDs' particular technical characteristics, rather than being limited to the old form-factor and housings of tubular fluorescents. The potential for emerging LED lighting technologies was noted by witnesses, including Witness Spellman in the 2009 goal-setting. *See. e.g.*, Witness Spellman Direct Testimony, Document No. 07271-09, at 59. This is another major omission to a technical potential estimate, as there are likely to be LED solutions for virtually every lighting application in commercial and industrial spaces.

Third, the Utilities identify only one data center-related measure, server virtualization. Data centers present openings for significant energy savings because they represent a growing percentage of electricity consumption in many jurisdictions. Therefore, the Utilities should consider other efficiency strategies and technologies ranging from the efficiency of the computing equipment to the power supply and HVAC systems. These represent yet another area where the technical potential likely falls short of the actual opportunity.

Fourth, in 2009, Witness Mosenthal noted the apparent omission of measures specific to water and wastewater treatment plants and to the agricultural sector. The updates do not seem to remedy this omission.

Fifth, in 2009, Witness Wilson, noted that efficient outdoor and street lighting measures were entirely omitted. Yet these measures represent substantial energy consumption, and they are clearly technically feasible. Nonetheless, they are still missing from the Utilities updates.

Last, the updates fail to account for ultra-low energy or net-zero energy buildings. Constructing such new buildings or retrofitting existing buildings to those standards is technically feasible, and thus should be included in the technical potential analysis. For example, an experimental super-energy-efficient residence in Lakeland, Florida demonstrated a 70% to 84% reduction in cooling loads. When the PV electric generation is included during the peak period, the home net demand was only 199 Watts, a 93% reduction in electricity requirements.[14]

Q: Are the Utilities' proposed DSM goals based on their technical potential estimates?

A. Yes, although not directly. The technical potential forms the basis for assessing the economic potential, which in turn forms the basis for the achievable potential. As discussed above in Section 4, the economic and achievable potential estimates are also flawed.

Q: What flaws have you identified in the Utilities' economic potential estimates?

A: The worst flaw is the Utilities' use of the RIM test to determine economic potential, as discussed above in in Section 4. Also problematic are the Utilities': (1) use of a two-year payback to screen efficiency measures for supposed free riders; (2) omission of non-energy benefits; and (3) omission of openings for DSM to replace aging, uneconomic generation. I elaborate on each of these flaws below.

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[14] Florida Solar Energy Center (FSEC). "ZEH: Lakeland, Florida."

Q: What is the problem with two-year payback screening?

A: The Utilities screen out any measure from their economic potential estimates if participant payback for that measure is less than two years without incentives. This is a blunt and overly-constrictive way to screen for free riders who would participate in programs without any incentives. As with several other flaws discussed in this testimony, the two-year payback screen was critiqued in the 2009 goal-setting docket. There, Witness Mosenthal described how the use of a two-year simple payback threshold is a critically flawed method to estimate economic potential for several reasons, including (1) inconsistencies between the Utilities' load forecast and the two-year payback method; and (2) the inaccurate assumption that all customers implement efficiency measures with a short payback whether or not the customers know the payback is short. To these, I add that the Utilities' two-year payback screening relies on the incorrect assumption that all customers have ready access to capital sufficient to take advantage of even highly cost-effective efficiency resources.

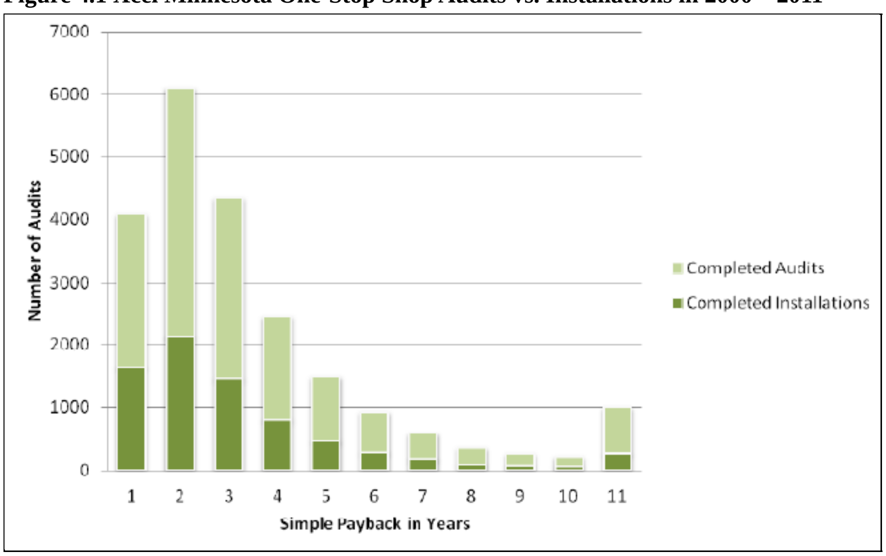
Q. Please explain these issues in detail.

A: First, the Utilities' base load forecast should already include naturally occurring DSM, which is essentially the impact from supposed free riders in an efficiency program. Accordingly, the baseline penetration of such measures that are naturally adopted without incentives should be 100%, and the Utilities' baseline forecast should reflect this. However, the technical and economic potential estimates actually assume some non-zero penetration of these measures, and therefore estimates some non-zero potential which is then removed from the potential estimate. This implies that they are in fact *not* currently installed and *not* reflected in the base load forecast.

Essentially, the Utilities try to "have it both ways" by claiming all these measures would be adopted naturally without incentives, but then the Utilities proceed to estimate DSM potential as though these measures are not adopted without incentives. If the Utilities have not included the impact of naturally occurring efficiency in their load forecast, then it is inappropriate to also omit it from the assessment of potential. That is, it should appear in one of these locations. If it does not, then the utility's need for future capacity and energy supply is overstated and the ability of efficiency to reduce that need is understated.

Second, the Utilities continue to assume that all customers know and understand the simple payback when buying efficient appliances or equipment. *See*, *e.g*., Direct Testimony of Witness Deason, Document No. 01474-14, at 27. There are many customers who do not have time or sufficient understanding to think about whether they can reduce their energy bills and whether or not an initial investment will be recouped. Even when customers do understand that efficiency investments provide a good return on investment, they may not follow through with those investments for myriad reasons. For example, Xcel Minnesota's innovative small business program, One-Stop Efficiency Shop^{SM}, identified many small business customers who did not adopt DSM even with simple paybacks in the range of 1 to 2 years, as shown in Figure 4.1. More than half of the customers with completed audits did not install DSM measures despite highly favorable returns.

Figure 4.1 Xcel Minnesota One-Stop Shop Audits vs. Installations in 2000 – 2011[15]



Last, even when customers understand the return on their efficiency investment and want to proceed to make that investment, they may not have access to the necessary capital

[15] Kristen Funk, *Small Business Energy Efficiency: Roadmap to Program Design*, Proceedings of the 2012 ACEEE Summer Study on Energy Efficiency in Buildings, August 2012.

monies. This is particularly true of low-income and fixed-income customers and new home-owners who are fully extended with credit obligations. Utility-sponsored DSM programs can assist with such consumers by offering low or zero interest loans.

In summary, it is clear that assuming that all measures with a two-year simple payback are automatically captured by the marketplace without any intervention is a gross over-simplification that dramatically reduces the achievable potential that utility efficiency programs should be addressing.

Q: Do the Utilities' present any information that supports your contention that not all customers will automatically take advantage of opportunities with a simple payback of less than two years?

A. Yes, the two-year payback threshold conflicts with Itron's 2009 Technical Potential Study, which clearly indicates that far less than 100% of customers will adopt measures with even a better return on investment. For example, DEF applies a payback-acceptance curve to determine maximum expected participation rates by measure. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, at 32. The maximum participation rates are presented in several Excel worksheets that DEF provided in response to Sierra Club's First Set of Interrogatories, No. 1-18. According to those worksheets, the maximum adoption rate for a residential measure with a two-year payback is approximately 42%; for a commercial measure it is just over 30%. Yet the Utilities' screening methodology would assume 100% penetration at two years, without intervention by their efficiency programs. Even at a one-year simple payback, the maximum adoption rates are just 51% for residential customers and 60% for commercial customers, still far below universal acceptance. The Utilities' assumption of maximum adoption rate and free-ridership are therefore internally inconsistent.

Q: Has the Commission expressed any concern with the two-year payback screen?

A: Yes. In the last round of goal-setting, the Commission noted that screen eliminates a substantial amount of potential savings. *See* Order No. PSC-09-0855-FOF-EG, at 9. As a result, the Commission increased the proposal goals for several utilities to account for the potential savings from several residential measures that the Utilities would have eliminated using the two-year payback screen.

Q: Did the Utilities' revise their approach in response to the Commission's Order?

A: No. For example, DEF's filing states that "the first step in the determination of economic potential was to evaluate and account for free-ridership by screening out any measure that had a participant payback of less than two years without a utility incentive." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 29-30.

Q: What is the effect of this approach to assessing free riders?

A: It is significant. For instance, FPL eliminated nearly a quarter of the DSM potential using this screen. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-5 (showing that FPL eschewed 210 measures out of the total of 850 measures based on the two-year payback year screen under the TRC Test).

<u>The Resource Planning Process is Driven Entirely by Rate Impacts</u>

Q. What is the primary criterion that the Utilities use to set their DSM goals?

A. FPL and DEF both set their DSM goals by including only those DSM measures that will not increase electricity rates. FPL calculates a levelized system average electric rate for each resource plan, and then the "rate metric is used as the primary economic basis by which the resource plans, and the amount of DSM in each resource plan, are evaluated." Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF has not identified its primary criterion for selecting DSM. However, DEF's proposed DSM goal is essentially the same as its estimate of achievable potential under the RIM test, indicating that DEF used rate impacts to set its DSM goals. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1 & HG-12.

Q. What is wrong with using rate impacts as the primary criterion to set DSM goals?

A. In Section 3 I describe several fundamental flaws of screening DSM programs with the RIM test; i.e., rate impacts. All of those points are relevant to the Utilities' resource planning process. To summarize:

- Using rate impacts as the primary criterion to select DSM programs conflicts with FEECA's requirements and policy goals.

- Lost revenues are not a “new” cost created by DSM programs; they are instead driven by costs already included in rates. In other words, they are “sunk” costs, and should not be used to determine cost-effectiveness.
- Using rate impacts as the primary criterion to select DSM programs can lead to perverse outcomes; where the opportunity to significantly reduce utility system costs and customer bills may be forgone to avoid a very small increase in rates.
- Using rate impacts as the primary criterion to select DSM programs is inconsistent with the treatment of supply-side resources, which can also lead to cross-subsidization between customers.
- The Utilities calculate rate impacts incorrectly, by estimating lost revenues on the basis of the full electricity rate, as opposed to just the fixed portion of electricity rates. This results in lost revenue estimates that could be more than double what the correct number would be.
- The Utilities calculate rate impacts incorrectly for another reason, by assuming that base rates will increase every year, when in fact base rates only increase at the time of a rate case. Consequently, the Utilities’ estimates of rate impacts are grossly overstated.

Furthermore, FPL and DEF’s resource planning process is inconsistent with standard industry practice for integrated resource planning. All states that I am aware of that use integrated resource planning practices use the minimization of the present value of revenue requirements as the primary criterion for selecting the preferred resource plan.

Q. Do the Utilities’ resource planning processes highlight any additional reasons why rate impacts should not be used as the primary criterion for setting DSM goals?

A. Yes. FPL’s own results indicate that the rate impacts of DSM are likely to be very small. Table 4.2 presents the results of FPL’s resource planning process, in terms of the levelized system avenge electric rate (cents/kWh). Table 4.2 also presents the difference in levelized average system rates between the Supply Only case and the other cases, as well as the difference between the RIM 337 MW case and the other cases. Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-11.

Table 4.2 Results of FPL's Resource Planning Process

Resource Plan	Levelized System Average Rate	Difference From Supply Only	Difference from RIM 337 MW
Supply Only	11.7419	0.000%	0.006%
RIM 337MW	11.7412	-0.006%	0.000%
TRC 337 MW	11.7579	0.136%	0.142%
RIM 526 MW	11.7431	0.010%	0.016%
TRC 576 MW	11.7636	0.185%	0.191%

As indicated, there are very small differences in levelized rates between the plans. The levelized rates for the TRC 337 MW plan and the TRC 576 MW plan are only 0.136 percent and 0.185 percent higher than the rate for the Supply Only plan. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described in Section 3. A proper estimate of rate impacts would indicate even lower impacts than the impacts presented in Table 5.1.

Q. Does DEF provide any information on the potential rate impacts of its DSM programs?

A. Only a little. DEF estimates a typical residential customer's rates under the RIM test and the TRC test. The results are summarized in Table 4.3. *See* Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-2 & HG-3. I estimate the rate impacts by calculating the percent difference between rates under the RIM the TRC scenarios.

Table 4.3 Residential Customer Rate Estimates

Year	RIM ($/month)	TRC ($/month)	Difference (percent)
2015	1,820	1,829	0.5%
2016	1,802	1,811	0.5%
2017	1,911	1,919	0.4%
2018	1,972	1,980	0.4%
2019	2,103	2,111	0.4%
2020	2,129	2,136	0.3%
2021	2,190	2,195	0.2%
2022	2,235	2,238	0.1%
2023	2,252	2,254	0.1%
2024	2,246	2,247	0.0%

The rate impacts presented in Table 4.3 are relatively small, ranging from 0.5 percent to 0.1 percent. Note that these rate impacts are based on lost revenue estimates that are grossly overstated, as described above in Section 3. A proper estimate of rate impacts would indicate even lower impacts than those presented in Table 4.3. Further, the DEF rate impacts presented above do not account for the years after 2014, when the DSM installed in this period will continue to result in savings, and will therefore help to lower rates. From a long-term perspective (i.e., over the lives of the efficiency measures), the rate impacts would be significantly lower than those presented in Table 4.3.

Q. What conclusions do you draw from FPL's and DEF's rate impact results?

A. The rate impacts of FPL's and DEF's DSM plans are likely to be very small, so small as to be essentially unnoticeable by most customers. FPL's estimates in particular indicate that the actual rate impacts are likely to be "in the noise." By this I mean that the estimates are likely to be so small that they are within the rounding and uncertainty errors of the resource planning analysis. Therefore, the Commission should give the Utilities' rate impact estimates no weight in setting DSM goals. While the other Utilities provide even less information on rate impacts in their resource planning processes, I expect that the rate impacts from their DSM plans will also be very small, because those plans are of a comparable scale to FPL's and DEF's.

Also, it is helpful to keep these rate impact estimates in perspective. The rate impacts estimated by FPL and DEF, even if they were not overstated, are small relative to the other factors that cause rates to change over time. Rates typically increase by much, much higher amounts after a rate case. It is safe to assume that if FPL completes the construction of Turkey Point Units 6 and 7, rates will need to be increased by much more than the DSM rate impacts estimated by FPL and DEF. However, FPL's resource planning does not capture the potential benefits of postponing Turkey Point Units 6 and 7, as described below, and therefore ignores the potential for DSM programs to help postpone, mitigate or avoid the rate impacts associated with this expensive generation.

FPL and DEF Undervalue DSM by Conducting Two Economic Screens

Q. Please explain what you mean by conducting two economic screens.

A. Both FPL and DEF conduct a screen to determine economic potential, then they conduct a second screen using their resource planning models. FPL describes the first screen as Step 3 of its analysis, where FPL conducts a "preliminary" screening analysis against a single supply-side option, utilizing the Participant test, the RIM test, the TRC test and the "years-to-payback" test. Direct Testimony of Witness Sim, Document No. 01476-14, at16. The second screen occurs during FPL's Step 6, where the resource plans are analyzed from both economic and non-economic perspectives, and where the DSM measures are selected based upon the minimization of levelized rates. Direct Testimony of Witness Sim, Document No. 01476-14, at 54.

DEF explains that its first screen is conducted when each DSM measure is compared to the Base Optimal Supply-Side Plan, to determine sets of cost-effective DSM measures based on the RIM test, the TRC test, and the Participants test. The second screen is conducted when the cost-effective supply-side and demand-side portfolios are "optimized together to formulate integrated resource plans." Direct Testimony of Witness Guthrie, Document No. 01497-14, at 26-27.

Q. Is there any problem with conducting two economic screens in this way?

A. Yes. The problem with this approach is that the first screen can eliminate a lot of potential DSM measures, before they even get a chance to be integrated and supposedly "optimized" with supply-side resources.[16] This approach is especially problematic if the first screen is unduly constrained, either by using incorrect free-rider assumptions, by using incorrect definitions of the screening tests, or by ignoring some key benefits such as avoided GHG emissions—all of these flaws appear in DEF and FPL's methods. Consequently, when DEF and FPL insert their narrowly-defined set of "cost-effective"

[16] As described in the following subsection, FPL does not actually optimize the combination of supply-side and demand-side options. This, however, does not mitigate the flaws identified in this subsection.

DSM measures into their resource planning process, there are too few DSM measures to meet resource planning needs, and DSM's value is significantly understated.

This practice essentially results in "double-screening" of DSM measures. I am aware of many states that screen DSM using a simple economic screen without resource modeling, and I am aware of many states that screen DSM using a resource planning process, but I am not aware of any states that use both combined. For good reason: doing so severely confines the resource planning process; needlessly complicates DSM screening; and obscures the critical fact that DSM is the lowest-cost, lowest-risk resource.

FPL Significantly Understates Avoided Capacity Benefits

Q. Please summarize how FPL compares DSM measures to supply-side resources.

A. FPL prepares a Supply-Only resource plan, which does not include any new DSM measures after 2014. This plan includes five approved and/or planned change to FPL's generating system, including: (a) retirement of existing Putnam units; (b) the completion of Port Everglades modernization; (c) the removal of existing gas turbines and the addition of 5 new combustion turbines in Broward County; the addition of the firm capacity portion of the EcoGen power purchase agreement; and the addition of Turkey Point Units 6 and 7. Direct Testimony of Witness Sim, Document No. 01476-14, at 21.

In the resource plans that include DSM, FPL includes a 1,269 MW combined cycle unit, as well as various amounts of purchase power agreements. *Id.*, Exhibit SRS-10. These are the resources that are potentially avoidable by DSM measures.

Q. Is this an appropriate way to compare demand-side resources to supply-side resources?

A. No. This methodology significantly understates the potential for DSM to help reduce capacity costs, by fixing the amount of capacity in the system that can be deferred, reduced or avoided by DSM.

First, this methodology freezes in place the five potential changes to FPL's generating system listed above. This means that DSM measures cannot defer, reduce the size of, or avoid several future supply-side resources, such as Turkey Point Unites 6 and 7, or new combustion turbines. As shown in Sections 2 and 5, DSM costs significantly less than new supply-side resources, and could play a role in deferring, reducing or avoiding new supply-side capacity. The proposed Turkey Point units, in particular, are expected to be very expensive, and involve considerable risks for the FPL's customers. Any opportunity to further delay these units could offer significant benefits to customers. These benefits are not captured in FPL's resource planning process.

Second, the combined cycle unit that FPL used as the potentially avoidable unit was modeled with the fixed size of 1,269 MW. One of the advantages of combined cycle units is that they can be constructed within a wide range of sizes to best match system needs. DSM programs could potentially reduce the size of this unit, thereby saving significant capacity costs. FPL's methodology did not allow for this potential savings opportunity to even be investigated in its resource planning process.

Third, FPL does not even attempt to optimize supply-side capacity options relative to demand-side capacity options. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs. *See* Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL does not use its optimization model to identify the best mix of supply-side and demand-side capacity resources. *See* FPL Responses to Sierra Club's Second Set of Interrogatories, Nos. SC-1-31 and SC-1-54. As a result, FPL has not investigated a variety of DSM plans that could potentially reduce utility system costs. This lack of modeling, combined with the first two points above, where FPL considers only a very limited amount of capacity options that can be avoided, demonstrates that FPL has significantly understated the potential for DSM measures to defer, reduce or avoid new capacity resources, thereby understating avoided capacity costs.

<u>FPL's Planning Criteria Ignores Avoided Energy Benefits</u>

Q. How does FPL determine the amount of DSM that should be included in its resource plans and DSM goals?

A. FPL uses a "reserve margin analysis" to estimate supply-side and demand-side capacity needs, as demonstrated in Direct Testimony of Witness Sim, Document No. 01476-14, Exhibit SRS-8. FPL identifies the amount of capacity needed to meet its 20 percent reserve margin, either using supply-side or demand-side resources. In the DSM resource plan, FPL assumes the installation of enough DSM to meet any deficiency in the reserve margin, and no more. *Id*. at 41-43. This presumes that DSM measures can only be installed when they are needed for capacity or reliability purposes.

Q. Can DSM measures only be installed when there is a capacity need?

A. No, not at all. FPL ignores the fact that DSM can reduce energy costs, by reducing fuel consumption, even if there is no need for new capacity. FPL thus ignores one of the key benefits of DSM.

Further, FPL's DSM screening practices conflict with standard industry practice, and in fact conflicts with FPL's screening practices for supply-side resources. That is, if energy impacts were ignored on the supply-side, then peaking combustion turbines would be the lowest-cost way to meet future peak demand. Also, there would be no need to build baseload units, such as combined cycle facilities, conventional steam facilities, or nuclear facilities.

Clearly, this is not an appropriate way to plan a utility system. In fact, FPL describes the importance of considering both capacity and energy benefits when developing future resource plans, and states that it is necessary to "capture and accurately compare all of the impacts that competing resource options with different capacity amounts, terms-of-service, heat rates, types of fuel, MW and GWh reduction impacts, and costs will have on FPL's system." Direct Testimony of Witness Sim, Document No. 01476-14, at 43. FPL has failed to do so in its DSM planning, has essentially ignored DMS' energy benefits, and has thus dramatically understated the economic and achievable DSM potential.

<u>The Utilities' Fundamentally-Flawed Resource Planning Eliminates Most DSM</u>

Q. What are the ultimate implications of these flaws in the Utilities' resource planning process, in terms of setting DSM goals?

A. The Utilities' screening process rejects nearly all DSM programs leading to extremely low proposed DSM goals. Figures 4.1 through 4.4 present the bottom-line screening results for FPL and DEF, showing the amount of the technical potential, the economic potential under the RIM and the TRC tests, and the proposed DSM goals. For each company the first figure is for the energy savings (in terms of GWh), and the second figure is for capacity savings (in terms of MW). As indicated in the figures, the proposed DSM goals are a small fraction of the technical, economic and achievable potential.

Figure 4.1 FPL Efficiency Savings at Various Screening Levels (GWh)[17]

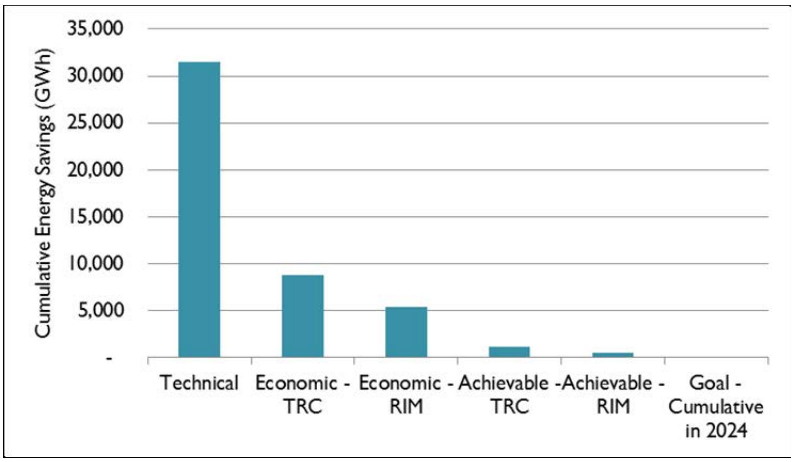
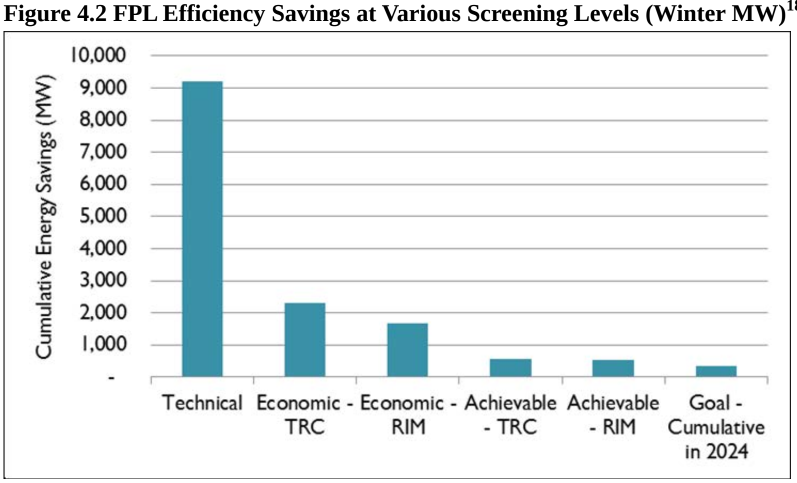


Figure 4.2 FPL Efficiency Savings at Various Screening Levels (Winter MW)[18]



[17] Based on Direct Testimony of Thomas Koch, Document No. 01475-14, Exhibits TRK-4, TRK-5, TRK-6, and TRK-7.
[18] *Id*.

Figure 4.3 DEF Efficiency Savings at Various Screening Levels (GWh)[19]

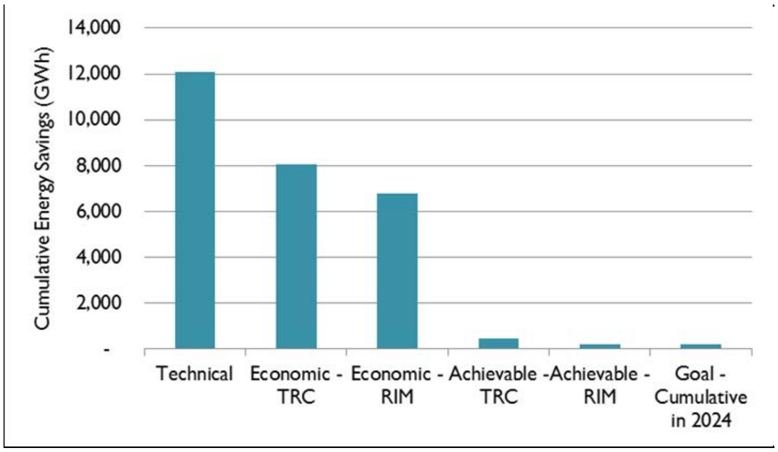
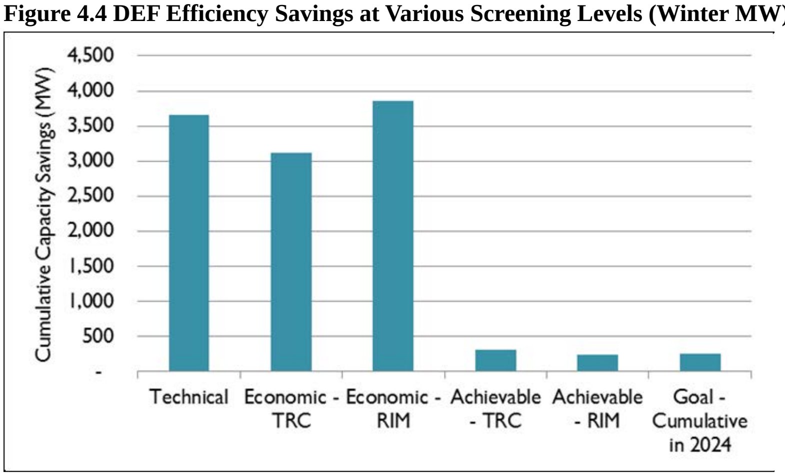


Figure 4.4 DEF Efficiency Savings at Various Screening Levels (Winter MW)[20]



Q. What do these results say about the Utilities' planning analysis?

A. First, recall that the Utilities' technical potential estimates are understated, for the reasons described above. Therefore, the DSM technical potential estimates should be higher than those presented above.

Second, the differences between the technical potential and the economic potential estimates are driven by applying the TRC, RIM and years-to-payback screens. These differences have a dramatic impact on the amount of economic potential, especially for

[19] Based on Direct Testimony of Witness Guthrie, Document No. 01497-14, Exhibits HG-1, HG-5, HG-7, HG-8, HG-12, and HG-13.
[20] *Id*.

FPL. Given the flaws in the Utilities' attempts to use the RIM and TRC tests, as described in Section 3, and that a two-year-payback screen should not be applied at all, the economic potential estimates are clearly too low.

Third, the differences between economic and achievable potential estimates are driven primarily by the Utilities' assumptions regarding maximum incentive amounts and maximum customer signup rates. As described above, these assumptions are overly simplistic and do not account for the many opportunities for the Utilities to promote customer participation through program marketing and delivery options.

Fourth, the differences between FPL's achievable potential estimates and DSM goals are due entirely to FPL's erroneous assumption that DSM can only be implemented for the purposes of meeting reliability requirements. The extent of this limitation is not apparent in the figures above, due to the scale of the vertical axis. FPL's cumulative achievable potential is estimated to be 526 GWh, but FPL has set its DSM goal at only 59 GWh. In other words, FPL has reduced its DSM goals by roughly nine times, because of FPL's incorrect assumption that DSM can only be implemented for the purposes of meeting reliability requirements.

Q. Are there other conclusions that can be drawn from the Utilities' resource planning processes?

A. The Utilities' resource planning process prioritize load management programs (i.e., those that curtail peak demand only), and place little, if any, priority on DSM programs (i.e., those that curtail both energy consumption and peak demand). Specifically, the Utilities' misguided view that DSM can only be implemented to meet reliability requirements strongly favors load management over energy efficiency.

Table 4.3 below provides weighted average summer peak reduction factors for the DSM measures being selected for different potential estimates and scenarios for FPL and DEF. While there are some differences between the Utilities, the Utilities selected resources that offer significantly more peak reduction per MWh energy savings in their achievable potential estimates and proposed goals. For example, FPL's technical potential on average reduces about 0.3 kW summer peak per MWh energy savings, but FPL's goal is expected to reduce about 5.7 kW summer peak per MWh energy savings.

Table 4.3 Peak Reduction Factor by Scenario for FPL and DEF (kW peak per MWh)

Scenario	FPL	DEF
Technical	0.29	0.30
Economic TRC	0.26	0.39
Economic RIM	0.31	0.57
Achievable TRC	0.53	0.67
Achievable RIM	1.00	1.33
Goal	5.68	1.33

Q. Is there anything wrong with placing a high priority on load management programs?

A. No, not necessarily. Load management programs offer a very low-cost opportunity for the Utilities to reduce demand in the most expensive hours of the year. I encourage the Utilities to maintain, or expand, these programs. My concern is that the Utilities place too much emphasis on load management programs, and not enough emphasis on energy efficiency programs. In doing so, the Utilities are missing the opportunity to significantly reduce electricity costs and to help "protect the health, prosperity and general welfare of the state and its citizens," pursuant to Section 366.81, F.S.

5. THE CENTRAL ISSUE: BALANCING RATE AND BILL IMPACTS

Q. Why is it so important that the Utilities and the Commission strike an appropriate balance between rate impacts and bill impacts?

A. As noted above, this is the primary challenge facing the Commission in setting DSM goals. DSM offers many advantages, with the primary advantage being that DSM reduces utility system costs and thereby reduces customer bills. The one (and only) countervailing consideration is that DSM can potentially increase electricity rates. To understand the implications of rate impacts, it is necessary to consider three important factors: rate impacts, bill impacts, and efficiency program participation rates. Taken together, these three factors indicate the extent to which customers as a whole will benefit from DSM.

Q. Do the Utilities' provide any meaningful information on these three factors in their filings in this docket?

A. No. As described above, the Utilities' analyses of rate impacts are so misguided and replete with flaws that they provide no information that would be useful to the Commission. In fact, the rate impact information that the Utilities provide is very misleading and should be ignored in its entirety. The Utilities' TRC analyses are also flawed, particularly because they ignore several key benefits such as avoided GHG regulatory compliance costs and participant non-energy benefits. Finally, the Utilities do not even provide results for the Utility Costs test, which is the one test that could provide the most information about the impacts on utility revenue requirements and thus the impacts on customer bills.

Q. How, then, do you recommend that the Commission consider the important issues regarding rate impacts and bill impacts?

A. I provide below some high-level information regarding the issues of rate, bills and participants. This information is helpful in illustrating the key tradeoffs that should be considered in setting DSM goals.

DSM Rate Impacts Will be Very Small

Q. How do you recommend that the Commission consider rate impacts associated with the DSM goals?

A. There is very little evidence presented in this case on what the actual rate impacts of the Utilities' DSM goals are likely to be. The Utilities estimates of lost revenues and rate impacts are clearly overstated and therefore unreliable. Even with this caveat, FPL's and DEF's own results suggest that the rate impacts of the DSM plans they have analyzed are likely to be very small, so small as to be unnoticeable by most customers. For these reasons, I recommend that the Commission give very little weight to concerns about the DSM goals discussed in this docket imposing an undue burden on customers as a result of rate impacts.

Q. Has the Commission recently issued an order indicating what an undue rate impact might be?

A. Yes. In Docket No. 1001155-EG, the Commission considered the potential rate impacts of FPL's DSM Plan proposed in that docket. The Commission determined that rate impacts of FPL's proposed DSM plan would cause an undue rate impact on customers. Order No. PSC-11-0346-PAA-EG, at 4. The Commission, therefore, rejected FPL's proposed DSM plan, and required FPL to maintain its existing DSM Plan because its rate impacts were determined to be relatively minor. Order No. PSC-11-0346-PAA-EG, at 5.

Q. How does that precedent impact your assessment of rate impacts here?

A. The Commission's Proposed Agency Action Order in Docket No. 1001155-EG included an estimate of the potential rate impacts of the proposed DSM Plan on a typical residential customer. Those rate impacts were estimated by determining the Energy Conservation Cost Recovery (ECCR) charge needed to support FPL's proposed DSM Plan, and adding those costs to the estimated residential bill. The results indicated that typical residential customer bills could increase in the range of 1.9 – 3.4 percent. Order No. PSC-11-0346-PAA-EG, Table 1.

The methodology used to estimate these rate impacts is very simplistic and does not account for the fact the DSM programs also exert downward pressure on rates. DSM programs reduce generation, transmission, distribution and other costs, which reduces a utility's revenue requirements, which in turn reduces customer rates. These avoided costs are significant and will outweigh the increase in revenue requirements associated with the DSM costs. This downward pressure on rate impacts is not accounted for in the rate impact estimates presented in Order No. PSC-11-0346-PAA-EG.

The downward pressure on rates is especially important in light of the magnitude of rate impacts that result from the installation of baseload power plants. When FPL has a rate case to recover the costs associated with a new power plant, such as Turkey Point Units 6 and 7, there will likely be much higher rate impacts than any impacts associated with DSM programs. DSM can help offset, reduce, defer or even totally avoid some of the rate impacts of large new power plants, but the rate impact estimates presented in Order No.

PSC-11-0346-PAA-EG do not account for any of these benefits. Consequently, they significantly overstate the potential rate impacts from DSM programs, and should not be used in setting DSM goals.

<u>Higher DSM Goals Would Result in Lower Costs and Lower Bills</u>

Q. How do you recommend that the Commission consider bill impacts associated with the DSM goals?

A. As noted above, the Utilities' resource planning process provides little information regarding the extent to which DSM can reduce customer bills. Even worse, the Utilities' overly-complex and overly-constrained screening process actually obscures the undisputable fact that DSM costs significantly less than alternative supply-side resources.

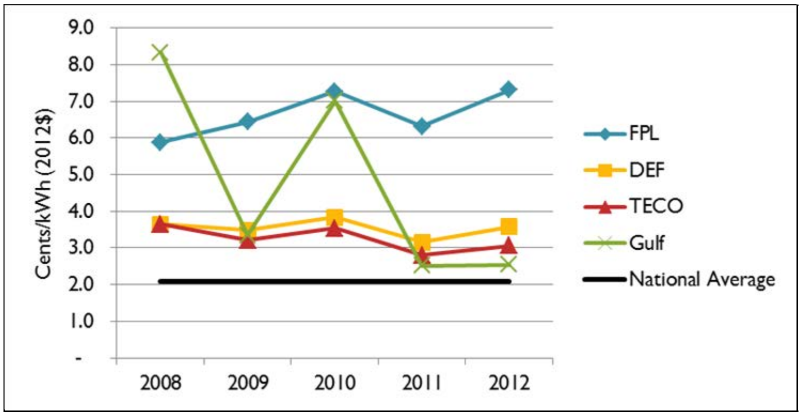
I provide some information below to illustrate this key point. I compare the "cost of saved energy" from DSM programs to the cost of generating energy from alternative sources, in terms of levelized costs.

Q. What is the cost of saved energy from DSM programs?

A. The cost of saved energy (in cents/kWh) is simply a ratio of the cost of implementing DSM programs (in dollars) divided by the energy savings (in GWh). The cost of saved energy can be presented in terms of either annual energy savings, lifetime energy savings, or in terms of levelized lifetime energy savings. I prefer to use levelized lifetime energy savings, because these can then be compared directly to levelized costs of supply-side alternatives.

Figure 5.1 presents the levelized cost of saved energy for the four largest electric utilities in Florida, for 2008 through 2012. It also presents the national average levelized cost of saved energy for 2012, for comparison purposes. As indicated, DEF and TECO have been achieving efficiency savings for roughly 3 to 4 cents/kWh; FPL has been achieving efficiency savings for roughly 6 to 7 cents/kWh; and Gulf's costs have varied considerably over this period.

Figure 5.1. Levelized Cost of Saved Energy: Florida Utilities versus National Average.[21]



Q. What conclusions do you draw from Figure 5.1?

A. First, the DSM programs offered in Florida are considerably more expensive than the national average. I expect this is due more to program design and implementation than it is due to anything unique about Florida.

Second, DEF and TECO have demonstrated that it is possible to implement DSM programs in Florida for roughly 3 to 4 cents/kWh. There is no reason why FPL and the other utilities cannot implement efficiency programs at this level of costs as well.

Third, no matter which utility you look at, DSM is significantly less expensive than supply-side alternatives.

Q. How do you know that DSM is significantly less expensive than supply-side alternatives?

A. Figure 5.2 compares the cost of several generation technologies to the cost of saved energy. The levelized cost of FPL's proposed Turkey Point nuclear unit is estimated by the Company to be roughly 16 cents/kWh.[22] The levelized cost of DEF's proposed Levy nuclear unit is estimated by Synapse Energy Economics to be roughly 17 cents/kWh as a

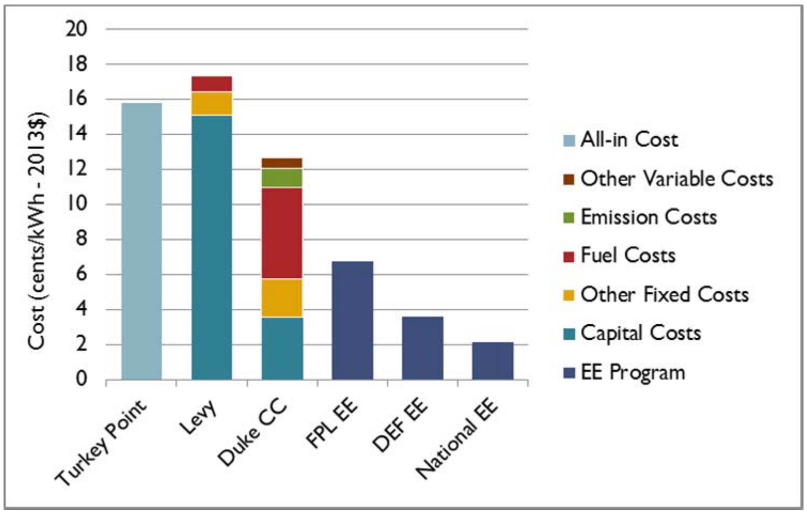
[21] Note that these costs and savings are for the energy efficiency programs offered by the Florida utilities. They do not include the costs or savings for the load management programs, because this metric is much less relevant for programs that have few energy savings.

[22] FPSC, "Hearing Proceedings of Docket No. 130009-EI, Nuclear Cost Recovery Clause" (August 14, 2013), Volume 4, at 821.

mid-point estimate.[23] The DEF CC unit is the cost of a combined cycle unit that DEF used in this docket in its resource planning process.[24] The cost of saved energy values for DEF, FPL and the national average are taken from Figure 5.1.

As indicated in Figure 5.2, the costs of DSM programs are well below those of the supply-side alternatives that those programs could potentially displace. Note that the avoided costs of transmission and distribution associated with the supply-side generation technologies are not included in Figure 5.2, making those resources look less expensive than they really are.[25] Also, note that the DSM programs can help reduce the reserve margin requirements (in MW), and reduce line losses, unlike the supply-side options.

Figure 5.2. Cost of Generation Technologies versus the Cost of Saved Energy



23 Synapse Energy Economics. “Big Risks, Better Alternatives - An Examination of Two Nuclear Energy Projects in the U.S.” October 6, 2011.

24 The cost estimate is based on the underlying cost assumptions for the “CC2X1 P1 - COMBINED CYCLE” unit provided in Excel file, “Sierra Club ROG 1-13 - Avoided Costs.xlsx” as part of Duke’s response to Sierra Club Interrogatory No. 1-13.

25 According to FPL’s response to Sierra Club Interrogatory No. 1-13, the avoided cost of transmission and distribution systems are approximately $150/kW-year and $27/kW-year respectively.

Q. Figure 5.1 presents supply-side and demand-side resource costs in a relatively simple format. Is it not necessary to account for more details of how the two types of resources would affect the utility system, by using resource planning processes?

A. A more detailed resource planning process would provide a better, more comprehensive picture of the costs and benefits of DSM programs in Florida. However, there are two very important conclusions that can be drawn from Figure 5.1, despite its simplicity.

First, DSM programs cost significantly less than supply-side resources. They can cost as little as 2, maybe 4, maybe 6 cents per kWh, while supply-side options cost as much as 12, 16, or even 17 cents/kWh (even before avoided transmission and distribution costs are factored in, or accounting for reserve margin benefits or line loss benefits).

Second, reduced costs from DSM programs will result in reduced customer bills. All of the costs that are shown in Figure 5.1 would eventually be included in a utility's revenue requirements, and passed on to customers. Therefore, the savings resulting from DSM programs would be passed on to customers in the form of lower average customer bills. In fact, the data in Figure 5.1 is the only data presented so far in this docket that provides any indication of how DSM might help reduce customer bills. None of the Utilities' analyses presents information on the impact on customer bills, and yet this is one of the key factors that the Commission should consider in setting DSM goals. I recommend that the Commission consider the information in Figure 5.1 when considering the bill impacts of the proposed DSM goals.

Program Participation Will Mitigate Rate Impacts

Q. Why is it so important to consider program participants, when analyzing rate and bill impacts?

A. Generally speaking, program participants are essentially shielded from the rate impacts of DSM programs; they experience reduced bills as a result of reduced consumption, regardless of any rate increases. Therefore, to the extent that rate impacts appear to be a problem, it is essential to consider the offsetting impact of program participation, in order to understand the extent of the problem.

Q. Do you have any information to offer regarding DSM participation rates?

A. Yes. Figures 5.3 and 5.4 present historic and forecast participation rates for FPL's DSM programs. These are taken from the Company's most recent Annual DSM Report.[26] The participation rates in these figures are based on the number of historic and forecast participants divided by the eligible population of participants. Note that the forecast of participants are based on placeholder goals that FPL was forecasting at the time it prepared the Annual DSM Report. If the Commission were to approve the lower DSM goals proposed by FPL in this docket, then the future participation rates would be much lower than those presented in Figures 6.3 and 6.4.

Figure 5.3. FPL Cumulative Participation Rates – Residential Programs

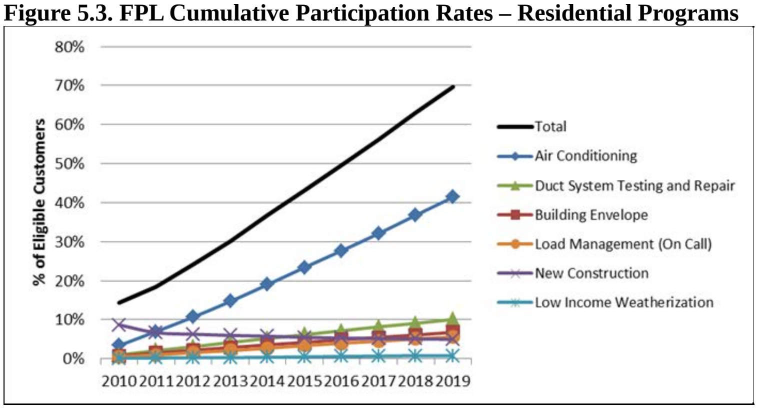
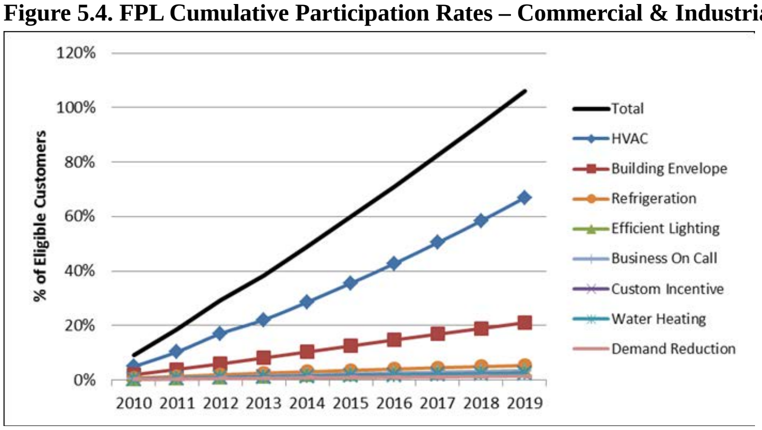


Figure 5.4. FPL Cumulative Participation Rates – Commercial & Industrial Programs



[26] FPL. "2013 Demand Side Management (DSM) Annual Report." February 28, 2014.

Q. What conclusions do you draw from the participation rates presented in Figures 5.3 and 5.4?

A. This information suggests that FPL would be able to serve a significant portion of its residential, commercial and industrial (C&I) customers with DSM programs—if FPL were to continue with the goals it had at the time of the Annual DSM report published in February this year. Roughly 40 percent of residential and 60 percent of C&I customers could be served with air conditioning or HVAC services. Roughly 10 percent of residential and 20 percent of C&I customers could be served with building envelope measures. The total amount of participation could reach up to 70 percent for residential customers, and 100 percent for C&I customers.

In addition, the participation information presented above does not include any of the customer participation that occurred prior to 2010. If this were included in the information presented above, then the cumulative participation rates would be significantly higher.

It is important to note that there are probably instances of multiple participation embedded in the participation rates presented in Figures 6.4 and 6.5. Multiple participation occurs when a single customer participates in more than one program in a single year, or in more than one program across years. Multiple participation is common in DSM programs, and is not discouraged; in fact it is encouraged. I mention this phenomenon to note that in some cases the participation information presented in Figure 5.4 and 6.5 may be somewhat over stated.

In sum, it is safe to conclude that a large portion of FPL's customers has been, or could be, served by the DSM programs. To the extent that there are any significant rate impacts as a result of these programs, they will be offset by efficiency savings for a large portion of customers. This should be a central consideration when setting DSM goals.

<u>A Better Balance Between Reduced Costs Against Increased Rates</u>

Q. Please summarize the conclusions that you draw from the information above regarding rates, bills and participation.

A. There is no question that the Utilities could achieve significantly higher DSM goals, without causing a significant increase in electricity rates. The Utilities' own analysis shows that the rate impacts from higher DSM goals would be so small as to be in "the noise" of the analysis, and this result is from a resource planning process that *overstates* the rate impacts of DSM programs in many ways.

It is also clear that if the Utilities were to adopt significantly higher DSM goals, then customer bills would be reduced significantly. This is the basic conclusion from a straightforward comparison of the costs of supply-side and demand-side resources; unencumbered by opaque, unduly complex and constraining resource planning practices.

Furthermore, the Utilities could provide DSM services to a large portion of their customer base, thereby offsetting any rate impacts that do occur. This could be achieved by maintaining the DSM goals that were previously approved by the Commission in the 2009 goal-setting dockets. Participation could be expanded even further with higher DSM goals.

In sum, this high-level consideration of rate impacts, bill impacts and participation rates indicates that increased DSM goals would lead to greater benefits to "the general body of ratepayers as a whole," consistent with Section 366.82(3)(b), F.S. This is a much better indication of the issues at stake in these dockets than resource planning results presented by the Utilities.

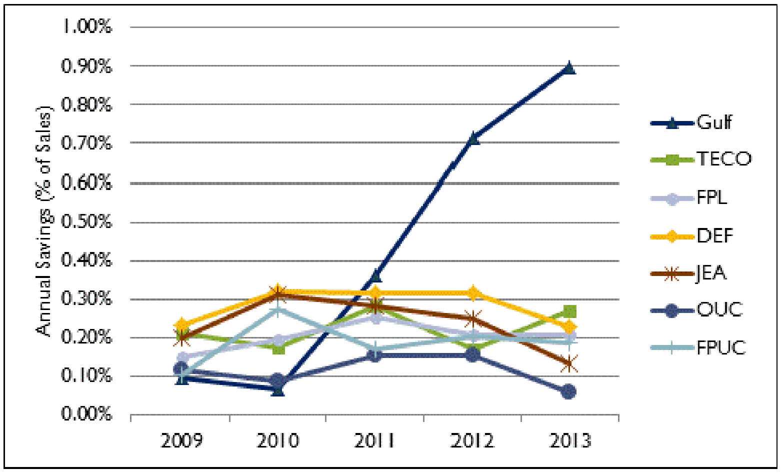
6. ENERGY EFFICIENCY SAVINGS AND GOALS

<u>Efficiency Savings in Recent Years</u>

Q. Please summarize the efficiency savings that have been achieved in recent years.

A. Figure 6.1 provides an overview of the energy savings achieved by the FEECA utilities in recent years. The energy savings are presented in terms of annual energy saved as a percent of annual retail sales. This allows for an easy comparison of savings across utilities of different sizes. It also allows for easy comparison of savings across utilities in different states and regions of the country. As indicated, the Utilities saved roughly 0.1 percent to 0.3 percent of sales in this period, with Gulf achieving higher savings in the later years.

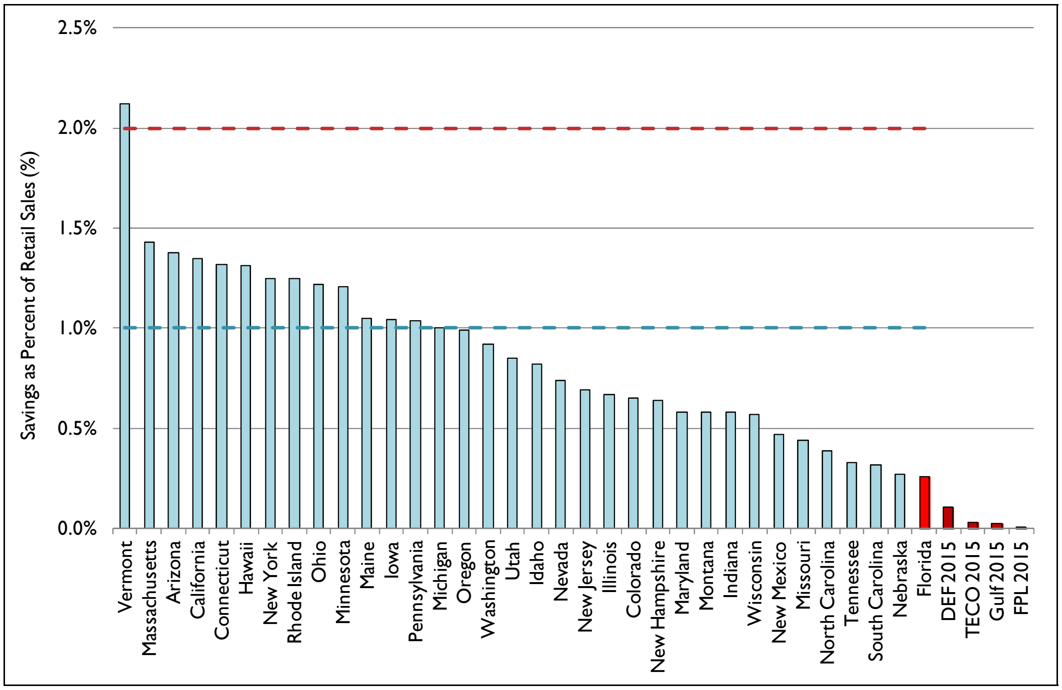
Figure 6.1 Efficiency Savings of Florida Utilities 2008 – 2013



Q. How do the Utilities' DSM savings in recent years compare with savings by utilities in other states?

A. Figure 6.2 presents the efficiency savings in 2011 from several states, including Florida, again in terms of percent of retail sales. The savings from all 50 states have been presented in order from the greatest to the lowest savings. To fit the graph onto the page, I have not presented the states that had less energy savings than Florida. As indicated, Florida's 2011 efficiency savings are less than those of 33 other states. Roughly 15 states achieved savings of 1 percent or more, and roughly half of all states achieved savings of 0.5 percent or more. In contrast, Florida saved just about 0.25 percent in 2011. Furthermore, these numbers are a little out of date; I am aware of many states that achieved higher levels of savings in 2012 than in 2011.

Figure 6.2 Efficiency Savings in 2011: Top US States and Florida



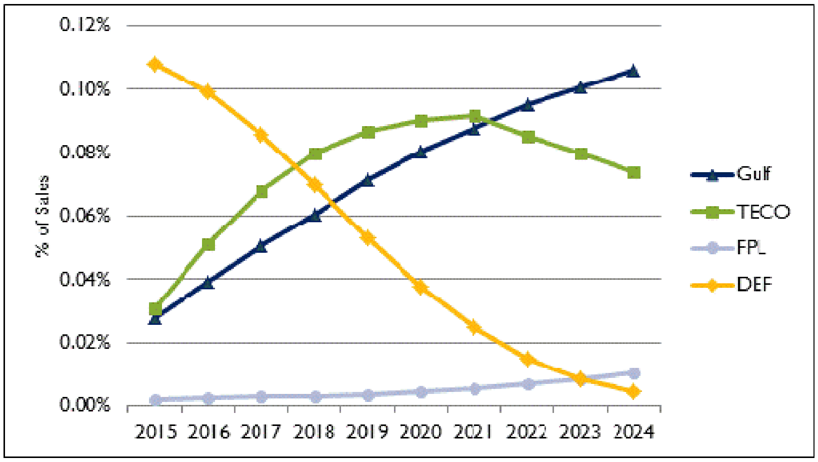
In sum, the Florida utilities are not one of the leading states in terms of delivering DSM savings. Figure 6.2 also presents the proposed 2015 DSM savings goals for the four largest Florida utilities. As indicated, the 2015 DSM goals are well below Florida's 2011 savings, and are well below the historic savings of many other states. I return to this point in the next subsection.

<u>The Utilities' Proposed Efficiency Goals</u>

Q. Please summarize the efficiency goals proposed by the Utilities.

A. Figure 6.3 presents the DSM savings goals proposed by the four largest FEECA utilities. As indicated, DEF's proposed goals start out higher than the others, d then decline significantly during this period. FPL's proposed goals start out much lower than the others and rise slightly during this period. TECO's proposed goals increase significantly at first, then decline in the second half of this period. Finally, Gulf's proposed goals increase significantly throughout this period.

Figure 6.3. Proposed Goals (2015-2024)



Q. How do these proposed goals compare with the amounts of savings achieved by the Utilities in recent years?

A. Figure 6.4 combines the historical savings from Figure 6.1, with the proposed goals presented in Figure 6.3. As indicated, the proposed DSM goals are dramatically lower than the amount of savings achieved in recent years.

Figure 6.4 Historic Savings and Proposed Energy Goals

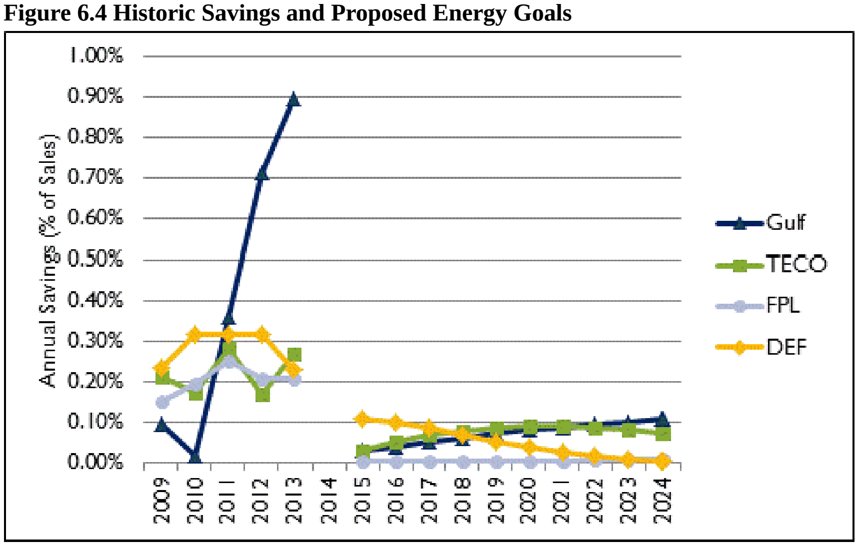


Table 6.1 Historic and Proposed Savings Goals (GWh)

	FPL	DEF	TECO	Gulf
2009	155	88	40	10
2010	204	124	34	8
2011	261	119	52	40
2012	211	115	32	76
2013	214	84	50	95
2014	---	---	---	---
2015	2	40	6	3
2016	3	37	10	4
2017	3	33	13	6
2018	4	27	15	7
2019	4	21	17	8
2020	5	15	18	9
2021	7	10	18	10
2022	8	6	17	11
2023	10	4	16	12
2024	13	2	15	13

Q. Are there any high-level conclusions that can be drawn from the historical and proposed savings levels presented in Figure 6.4?

A. Yes. First, the DSM goals proposed by these four utilities are well below the levels of efficiency savings that they themselves have achieved in recent years. FPL's proposed 2015 goal is less than the company's 2013 savings by a factor of 100. This is a dramatic reduction in DSM goals. DEF's 2015 goal is roughly half of its 2013 savings level. It is also remarkable that FPL is proposing to reduce its DSM goals by so much more than the reductions proposed by the other companies. There is no reason why there should be such striking differences between the goal reductions across the four utilities.

Second, these four utilities (FPL, DEF, TECO, and Gulf) are all proposing inconsistent trends for savings over the DSM goals period. Some propose a dramatic increase over the period, some propose a dramatic decrease over the period, and Gulf proposes both. There is no logical explanation for such differences in the trends over this period. These Utilities have roughly similar customer bases, and will be exposed to similar efficiency standards and building codes over this period. The differences between the savings trends across the utilities can only be explained by inappropriate assumptions and methodologies, poor planning practices, or some combination of both.

Third, the proposed 2015 goals are dramatically less than the savings achieved by other states, as indicated in Figure 6.2, above. In 2011, over half of the states in the US saved at least 0.5 percent of retail sales though DSM programs, and 15 states saved roughly 1.0 percent of retail sales or more. If the Commission were to accept FPL's proposed DSM goals, then *FPL's energy savings in 2015 would be less than the 2011energy savings achieved by every other state in the country*.

Q. The Utilities have argued that their DSM goals should be lower than in the past, because they have already implemented much of the efficiency savings available in Florida. Do you agree?

A. No. Relative to many other states the Utilities' DSM programs have not achieved large amounts of energy savings in the past. Figure 6.2 illustrates how small the Florida efficiency savings were in 2011 relative to other states. Data from earlier years demonstrate the same point. Relative to the achievements of many other states, the Utilities have left a large portion of the efficiency savings potential in Florida untapped.

In addition, the Utilities' argument is based on a very simplistic understanding of DSM programs, markets and opportunities. The potential for DSM savings is not a stagnant figure, that a utility can pursue for several years and then claim that it has finished the job. Instead, efficiency products are constantly being introduced into the marketplace, creating new opportunities for efficiency savings every year. The recent introduction of LED lighting products is but one example of how new products can create new opportunities for efficiency savings. Furthermore, and more importantly, utility DSM programs should constantly evolve to account for new developments in the market. Utility efficiency programs should constantly be seeking new efficiency measures to promote, considering new marketing and delivery opportunities, and looking for new ways to overcome customer barriers to DSM measures. This is how efficiency programs are designed in the leading states, and why those states have been able to achieve significantly higher savings than Florida in the past, and plan to achieve higher savings than Florida in the future. I address this point in more detail in the following subsection.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because avoided costs are lower than they have been in the past. Do you agree?

A. No. First, the Utilities have understated avoided costs by not properly accounting for GHG compliance costs and by ignoring participant non-energy benefits. If these costs were properly included in their analysis, then the economic potential for DSM would be higher than indicated by the Utilities.

Second, the Utilities' efficiency programs cost much less than supply-side alternatives, as indicated in Figure 5.1—even under the Utilities' current assumptions of avoided costs. This means there is still lots of room for the efficiency program benefits to exceed the costs, even though avoided costs are less than they were in the past.

Third, this argument would only make sense if the Utilities were implementing the total economic potential for DSM (i.e., all cost-effective energy efficiency), both in the past and proposing to do so going forward. If avoided costs decline for some reason, then the total economic potential for DSM would decline as well. However, the Utilities have not implemented the total economic potential in the past, and they do not propose to implement the total economic potential in the future. Their past savings and future goals are based on implementing the achievable efficiency potential, and only a portion of the achievable efficiency potential at that. This means that there is likely to be a significant amount of efficiency potential that is still available, despite the lower avoided costs.

Q. The Utilities try to argue that their DSM goals should be lower than in the past, because new building codes and efficiency standards will diminish the amount of efficiency available. Do you agree?

A. No, not entirely. It is true that increasing building codes and standards will make it more difficult to achieve DSM savings over time. However, this does not mean that the potential for efficiency savings will be reduced by anywhere near the amount indicated by the Utilities' proposed goals.

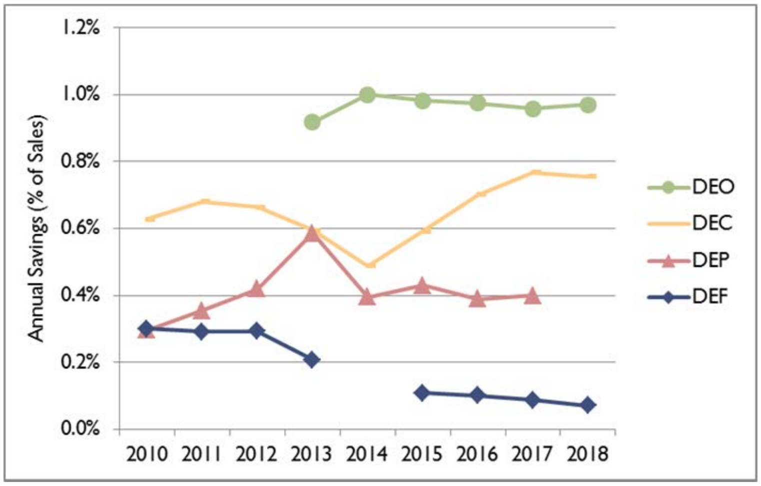
Figure 6.4 shows that some utilities propose future DSM goals that are a small fraction of their recent savings. DEF's proposed DSM goal for 2020 is roughly 15 GWh, which is six times lower than the savings that DEF achieved in 2013. Increasing efficiency standards and building codes will not have such a dramatic effect on the potential efficiency savings available in DEF's service territory. Furthermore, as new efficiency standards begin to take effect, the Utilities should modify their DSM programs to offer additional efficiency measures that are more efficient than the standards. Promoting the purchase of LED lighting products in response to the new federal lighting standards is one example of how utilities in general should respond to the new federal standards. In addition, as efficiency standards are applied to some end-uses (e.g., lighting), utilities should generally place greater emphasis on other types of end-uses where efficiency opportunities still remain.

<u>**Efficiency Goals in Florida Relative to Other States**</u>

Q. How do DEF's DSM savings goals compare with the efficiency savings of other Duke utilities?

A. Figure 6.5 presents DEF's efficiency savings in recent years, as well as proposed DSM goals, alongside those of Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and Duke Energy Ohio (DEO). As indicated, the other Duke companies have already achieved significantly higher levels of efficiency savings than DEF, and have set significantly higher goals for future efficiency savings.

Figure 6.5 Duke Florida Goals Relative to Duke Goals in Other States



Q. What conclusions do you draw from this comparison of efficiency goals across Duke's companies?

A. First, DEF should be able to achieve roughly the same goals as other Duke companies. There is no reason why DEF cannot implement the same types of efficiency programs, offer the same types of efficiency measures, and achieve roughly the same amount of customer participation as other Duke companies. As I describe in more detail below, the differences between these companies is more due to the regulatory environment in each state than the achievable efficiency potential. In addition, DEO, DEC and DEP have all achieved greater savings than DEF in recent years; thus, the goals for these other Duke companies contradict DEF's argument that it has already achieved much of the achievable efficiency potential available in Florida. If that argument were true, then DEO, DEC and DEP could not have saved more energy than DEF in the past and still have higher goals the future.

Furthermore, DEO, DEC and DEP will all be subject to the same federal efficiency standards as DEF; thus the goals of the other Duke companies contradicts DEF's arguments that the achievable potential in Florida is shrinking dramatically due to federal efficiency standards. Finally, even if one were to agree with DEF's arguments that there is less achievable efficiency potential in Florida relative to other states, which I do not, there is no way to justify the magnitude of the difference between DEF's proposed goals, and those of other Duke companies. DEF's proposed efficiency goals are roughly one-tenth the size of DEO's. This means that DEF is proposing to forgo 90 percent of the efficiency savings that DEO is able to achieve. There is no justification for depriving customers of such a large opportunity to reduce system costs and reduce customer bills.

Q. Are you aware of other states in the Southeast that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. I am aware of one state in the Southeast that has recently established significantly higher efficiency goals than those proposed by the Utilities. The Arkansas Public Service Commission recently issued a set of orders that outline several regulatory policies affecting the planning and implementation of DSM programs there. The orders require several significant changes to these regulatory policies, including the introduction of decoupling, the introduction of shareholder incentives, the requirement to incorporate non-energy benefits into the TRC test, and more. One of the key elements of the recent orders is a set of efficiency goals for the next several years. The Arkansas Commission has required that the electric utilities ramp up their efficiency programs over the next few years, so that they achieve savings equal to 1.0, 1.25 and 1.5 percent by 2014, 2015, and 2016, respectively. I have seen no evidence in this docket indicating that the Florida Commission cannot set comparable goals for the Florida utilities.

Q. Are you aware of other states in the US that are proposing significantly higher future efficiency savings than what the Utilities are proposing for their DSM goals?

A. Yes. I have been involved in three states that have achieved, and plan to continue to achieve, significantly more than what the Utilities are currently achieving or what the Utilities are proposing for their DSM goals.

Massachusetts: In 2012 the Massachusetts program administrators achieved electric efficiency savings equal to 2.1 percent of sales. The energy savings goals that the efficiency program administrators set for the years 2013 to 2015 are 2.50, 2.55 and 2.56 percent of sales each year, respectively. These goals have been approved by the Massachusetts Department of Public Utilities.

Rhode Island: In 2012, the Rhode Island program administrator achieved electric efficiency savings of 1.5 percent of sales. The energy savings goals for 2013 and 2014 are 2.05 and 2.44 percent of sales per year, respectively. These goals were approved by the Rhode Island Public Utilities Commission. The program administrator and other stakeholders are currently proposing energy savings goals for 2015-2016 equal to 2.50, 2.55 and 2.60 percent of sales each year, respectively. These goals have been approved by the Rhode Island Public Utility Commission.

Vermont: As noted above, Vermont has achieved significant energy savings of roughly 2 percent per year on average for the past five years, cumulatively achieving 10 percent savings over those years. The state currently has efficiency savings goals of roughly 2 percent per year for 2012 – 2014. The state is currently in the middle of a planning docket to set future efficiency savings goals, where the base case proposal is for annual savings goals to of roughly 1.7 percent of retail sales through 2019, 1.4 percent of retail sales through 2026, and 1.3 percent of retail sales through 2033.

Note that all three of these states have been implementing some of the most aggressive and successful efficiency programs in the country for many years. Also, note that the energy savings goals above account for federal efficiency standards, as well as state and local standards and building codes. Even so, *these states are setting DSM goals that are more than 100 hundred times greater than the goals being proposed by the Company in this docket.* There is no justification for such a wide disparity energy efficiency opportunities across these states.

Sierra Club Proposed Efficiency Goals

Q. Does the Sierra Club recommend that the Commission set different DSM goals than the goals proposed by the Utilities?

A. Yes. The Utilities' DSM goals are way too low, for all the reasons outlined above. I recommend that the Commission set significantly higher goals, in order to reduce costs to Florida electricity customers.

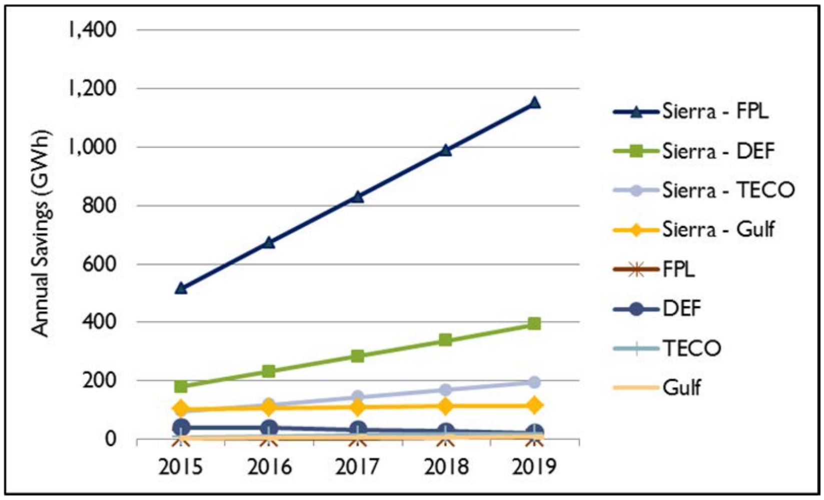
Q. What DSM goals do you recommend for the Florida utilities?

A. I recommend that the Commission set DSM goals such that each of the FEECA utilities will achieve annual efficiency savings equal to one percent of annual retail sales by 2019. These goals are presented in Table 6.2 and Figure 6.6

Table 6.2 Sierra Club DSM Goals (2015-2019) - GWh.

	FPL	DEF	TECO	Gulf
2015	516	180	95	103
2016	673	231	118	106
2017	830	283	143	109
2018	990	337	168	112
2019	1152	394	193	114

Figure 6.6 Sierra Club Goals Relative to Utilities' Goals (2015-2019) – Percent of Sales



Q. Do you recommend that the Commission set goals for capacity savings as well?

A. Yes. It is important that the Commission set goals for both energy (GWh) and capacity (MW) savings. Up until now I have focused on energy savings, as I believe that energy savings are an important indication of the magnitude of a utility's DSM efforts. However, the Commission should set capacity savings as well, as this is different indicator of the magnitude of a utility's DSM efforts.

In fact, it is important for the Commission to consider the ratio of energy savings per capacity savings (MW/GWh), because this provides an indication of the type of programs the Utilities offer—in particular the emphasis that the Utilities are placing on energy efficiency programs relative to load management programs.

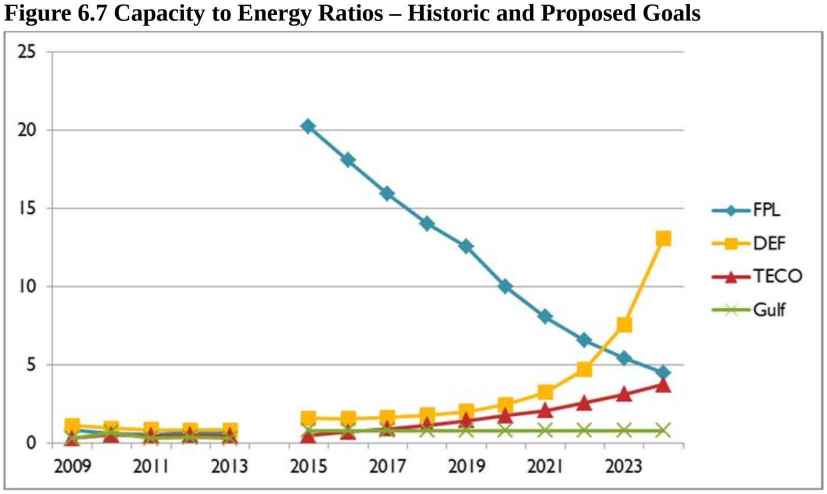
Q. Please explain why it is important for the Commission to consider the emphasis that the Utilities are placing on energy efficiency programs versus load management programs when setting DSM goals.

A. Energy efficiency and load management programs both offer benefits to the Utilities and their customers, and the Utilities should offer a proper balance of both types of programs. Load management programs offer some customers the opportunity to reduce their costs in some portions of the year. Energy efficiency programs offer a wider range of opportunities to a wider range of customers, relative to load management programs. Energy efficiency programs also offer customers the potential for reducing their energy consumption by a much greater amount that load management programs. Therefore, if too much priority is given to load management programs, at the expense of energy efficiency programs, then many customers will be deprived of opportunities to reduce their costs and bills.

Q. Do the Utilities' proposed DSM goals provide a good balance of load management and energy efficiency programs?

A. No. The Utilities have historically placed a much higher emphasis on load management programs and capacity savings than the utilities that I typically work with. More importantly, the Utilities' proposed goals make a dramatic shift toward increased capacity savings and load management, relative to historic programs. This is demonstrated clearly in Figure 6.7, which present capacity-to-energy ratios for the four Utilities, for historic and proposed DSM goals. Note that a higher capacity-to-energy ratio indicates a greater emphasis on load management, relative to energy efficiency.

Figure 6.7 Capacity to Energy Ratios – Historic and Proposed Goals



For some reason that the Company has not explained, FPL's capacity-to-energy ratio is much, much higher than it has been in past years, and is far higher than the other Utilities presented here. FPL's ratio then declines precipitously over the course of the next ten years. The other four utilities start their proposed DSM goals with higher than historic ratios, and then increase them over the course of the period, with DEF's ratios increasing dramatically more than the others.

Q. What conclusions do you draw from the capacity-to-energy ratios presented in Figure 6.7?

A. These capacity-to-energy ratios raise several concerns for the Commission to be aware of. First, these Utilities are clearly planning to make a dramatic shift away from energy efficiency programs toward load management programs. This suggests that they will not be placing much, if any, emphasis on energy efficiency savings, and may therefore deprive customers of large opportunities to reduce costs and bills.

Second, the FPL capacity-to-energy ratios do not make any sense. There is no reason why a utility would make such a major shift toward load management programs in the two years between 2013 and 2015, and then make a shift back away from load management programs. This result suggests that FPL's planning process is flawed, or that the Company is not paying sufficient attention to these important results of its own planning process, or both.

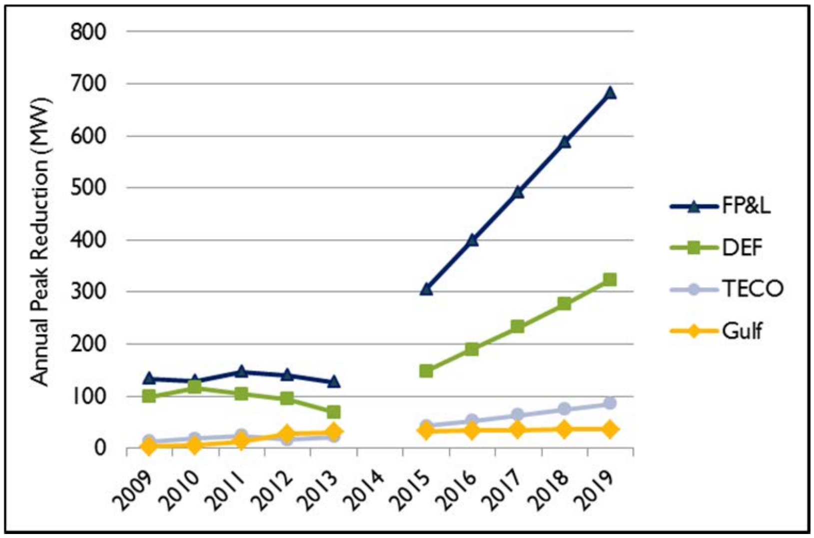
Third, there is a big difference in the ratios across the four Utilities presented in Figure 6.7. There is no good reason for such differences across utilities within the same state. These differences suggest that customers in some of the utilities will not be as well served by the DSM programs as other customers.

Fourth, the Company's do not mention this shift away from energy efficiency programs in their filings. Such an important change in their DSM profiles certainly warrants bringing to the Commission's attention, so that the Commission can make an informed decision on an important shift in DSM priorities and services to customers.

Q. How then have you set capacity DSM goals?

A. I start with the simplistic assumption that the ratio of capacity to energy savings achieved in 2013 is a reasonable balance of energy and capacity savings. I then hold this ratio fixed for the purpose of setting the Sierra Club DSM capacity goals, for each company. I then apply this ratio to the GWh savings of the Sierra Club DSM goals, to back out a capacity goal for each year. The results are provided in Figure 6.8 below.

Figure 6.8 Annual Peak Reduction from DSM – historic and Sierra Club Goals.



Q. Did you rely upon the Utilities' economic analyses or resource planning results in developing the Sierra Club DSM goals?

A. Yes, but only in a limited way. After reviewing the Utilities' economic analyses and resource planning results, I have determined that they suffer from so many fundamental flaws that they are of very limited value for the purpose of setting DSM goals. Even worse, they are misleading in several ways. My reasons for reaching this conclusion are described in detail in Sections 3 and 4 of my testimony.

Q. How then did you develop the Sierra Club DSM goals?

A. These goals are based upon the limited information of value that the Utilities did provide in their analyses in this docket, combined with my extensive knowledge of DSM opportunities, achievements and plans in other states.

As indicated in Section 5 of my testimony, and illustrated in Figure 5.2, there is no question that DSM programs in Florida cost significantly less than supply-side alternatives in Florida, and that increased efficiency savings will result in significantly lower costs to electricity customers.

In addition, I have considered the likely rate impacts of the Utilities' proposed DSM goals, as well as the potential rate impacts of the proposed Sierra Club goals, and it is clear that the average, long-term rate impacts of both sets of goals are likely to be very low. In the case of the Utilities' proposal, they are likely to be so low as to be "in the noise" of the analysis. The rate impacts of the Sierra Club goals will not be much higher than those of the Utilities' goals.

Furthermore, I have considered the likely customer participation rates that could result from the Utilities' goals, as well as the Sierra Club goals. Under both sets of goals, the Utilities should be able to serve a large portion of customers with efficiency programs, thereby offsetting any increases in rates that might occur. And the Sierra Club's higher goals should result in significantly greater participation levels than the Company's proposed goals, thereby mitigating customer equity and cross-subsidization concerns, and resulting in greater benefits for the "general body of ratepayers as a whole."

As described above, one of the key challenges in setting DSM goals is striking the appropriate balance between reduced costs and increased rates, which requires consideration of rates, bills and customer participation. On these points, the evidence that I present above indicates that the Sierra Club DSM goals strike a good balance and will be in customers' best interest.

Q. How do you know that the Utilities will be able to achieve the Sierra Club's DSM goals ?

A. I am confident that all Florida electric companies have the technical, economic and achievable potential of at least one percent of retail sales, for several reasons. Gulf achieved nearly this level of savings in 2013. If Gulf can achieve this level of savings, there is no reason that the other Utilities cannot. In addition, Duke Energy Ohio has achieved nearly this level of savings, and has goals to achieve one percent savings. If Duke Energy Ohio can achieve savings of one percent by 2014, then surely Duke Energy Florida can achieve similar savings levels by 2019.

Furthermore, I have seen the amounts of efficiency savings that are available in other states, that have been achieved in other states, and that are planned to be achieved in other states. I know the types of efficiency programs, marketing, delivery, customer incentives, and other factors that can be utilized to achieve savings of at least one percent of retail sales. There is no reason that the Utilities cannot achieve savings of at least one percent of retail sales by 2019, given the levels of savings that have been achieved in other states.

Q. But Florida is a different state from the other states. How can you be sure that the experience in other states is relevant to Florida?

A. First of all, I have worked on the topics of DSM planning and integrated resource planning for most of my 30-year career, and I have addressed these issues in states all across the US, as well as several Canadian provinces. I have prepared many national studies on DSM screening and analysis, including the studies for the National Efficiency Screening Project. I have prepared several regional studies where I estimated the potential for DSM and renewable resources over the long-term horizon; including a study of the Southeast, a study of the Midwest, and a study of the West. I have reviewed state-specific DSM plans and integrated resource plans in many states. In my experience, I have found that most, if not all, states face the same issues, the same barriers, and the roughly same potential for DSM savings. My findings and recommendations are based on my experiences in all of these states and provinces.

Second, the biggest difference between states and provinces affecting the development of DSM programs is the regulatory environment; it is not the customers, or the end-uses, or the climate of the state or province. The regulatory environment is created by legislation, by regulations, and by Commission orders. The legislation in Florida provides as much support for DSM as legislation in many states; this does not pose a barrier to DSM in any way. The Commission's regulations similarly are fairly supportive of DSM relative to other states; they do not pose a barrier to DSM either. The biggest difference between the regulatory environment in Florida and other states is the signals that the Commission sends regarding DSM screening. And the Commission has complete control over the signals that are sent from this point forward. In fact, I believe that given the right regulatory environment, and sufficient time, the Utilities should be able to achieve annual DSM savings of as much as two percent of retail sales. I recommend a DSM goal of one percent of sales by 2019 in this docket to allow time for the Utilities and the relevant trade allies to ramp up to this higher level of DSM savings.

Third, one of the biggest differences between Florida's regulatory environment and those of other states is that many of regulators and other stakeholders, especially those in the leading states, recognize that *well-designed, cost-effective DSM is good for customers*. By this I mean that the advantages that DSM offers customers (i.e., reduced bills, reduced generation costs, reduced transmission and distribution costs, increased reliability, reduced risk, environmental benefits, and more) far outweigh any disadvantages to customers (i.e., very small, if any, increases to long-term average rates). It is ironic, misguided, and very misleading for the Utilities to try to argue that they should limit their DSM goals to protect customers from alleged rate increases or potential cross-subsidization of customers. This implies that cost-effective DSM is somehow bad for customers, when in fact the opposite is true.

Note that while I am representing Sierra Club in this docket, roughly half of all of my clients are either consumer advocates or regulatory commissions. I make similar recommendations for those clients; all on the same concept that well-designed, cost-effective DSM is good for customers.

7. DEMAND-SIDE RENEWABLES

Solar PV Potential

Q. Please briefly describe the results of the technical potential estimates for solar PV by Duke and FPL.

A. As part of this docket, five of the seven utilities subject to FEECA have updated their original technical potential for solar photovoltaic (PV) along with other DSM measures that were estimated by Itron in 2009. The updates for solar PV have been made just to take into account the historical PV projects installed to date since the original study was conducted and the growth of the rooftop areas for additional PV capacity. The results are that Florida utilities still have plenty of PV technical potential. For example, FPL identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. DEF identified about 14 GW summer peak capacity (66% of summer peak) and 38,000 GWh annual generation potential (37% of sales) from PV. See Tables 7.1 and 7.2, below.

Table 7.1 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[27]

	Summer Peak Capacity MW			Annual Generation GWh		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	14,055	13,815	9	38,136	37,488	27
Duke	5,054	5,000	1	13,737	13,593	6

Table 7.2 Comparison of Solar PV Technical Potential Estimates for FPL and Duke[28]

	Summer Peak Capacity (% of 2012 Peak Demand)			Annual Generation (% of 2012 Sales)		
	2014 Estimate	2009 Estimate	Installation since 2009	2014 Estimate	2009 Estimate	Installation since 2009
FPL	66%	64%	0.04%	37%	37%	0.03%
Duke	56%	55%	0.01%	38%	37%	0.02%

Tables 7.1 and 7.2 also show that there have been very little solar PV installations in the Utilities service territories (i.e., cumulative increase of only 0.01% to 0.04% of peak load for the past 4 to 5 years), and the increase in PV capacity due to increased rooftop areas outpaced the capacity additions. This resulted in a slight increase in the total PV capacity potential for 2014 for the two utilities (about 2% increases for FPL and 1% for DEF) when compared with the original estimates made in 2009.

Q. How do the conclusions and methods of the Itron potential study compare with other technical potential estimates you are aware of?

A. Given that not all FEECA utilities have updated their PV potential estimates and new estimates are likely to be very similar to the original estimates based on our review of FPL and DEF's updates, I am comparing the 2009 Itron study results with the results from a recent national solar PV potential study by the National Renewable Energy Laboratory (NREL). For methodologies, Itron made no changes to the original methods

[27] Based on Thomas R. Koch's Exhibit TRK-4 for FPL, Document No. 01475-14, and Helena Guthrie's Exhibit HG-5 for DEF, Document No. 01497-14.

[28] 2012 sales and peak load data for FPL and DEF are from US EIA.

except subtracting the recent solar development and adding new roof space for additional solar.

NREL estimated technical potential of solar PV resources for each state across the United States in 2012 using the geographic information system (GIS). NREL analyzed the technical potential for solar capacity additions across multiple technologies. While Itron only studied the technical potential of rooftop PV installations in the state, NREL examined utility scale PV in both urban and rural settings, in addition to concentrated solar power potential., I will focus on the rooftop PV potential estimates in these two studies.

The conclusions of the NREL study are similar to those of the Itron study: although NREL predicts a higher potential capacity for rooftop solar in Florida, the two studies forecast a similar potential for energy generated through rooftop PV installations in the state. See Table 7.3 below.

Table 7.3 Comparison of Solar PV Potential Results for Florida

	NREL 2012	Itron 2009
GW of potential	49	30
GWh of potential	63,987	69,449
Given state energy consumption	231,210	159,795
Potential as % of Itron consumption assumption	40%	43%
Potential as % of NREL consumption assumption	28%	30%

Similar to the Itron study, the NREL study bases the rooftop PV technical potential calculation on three main variables: available rooftop area; size of the PV module; and the capacity factor for the given region.

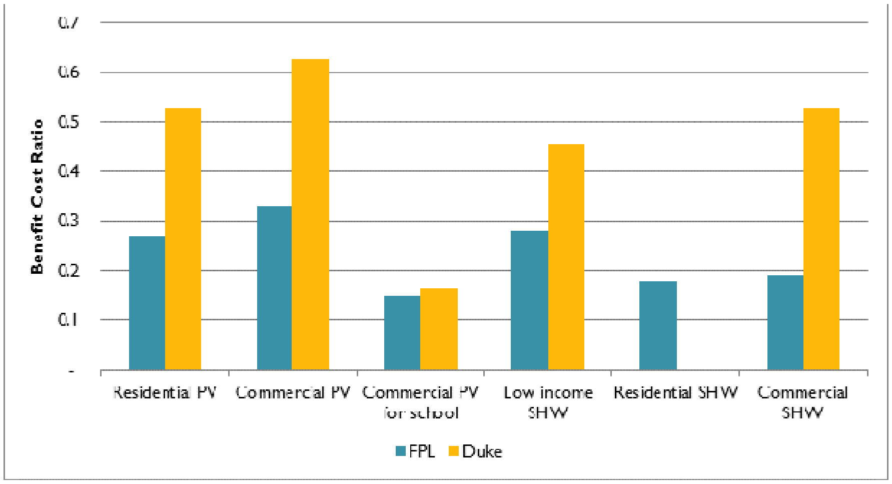
Q. Please briefly describe the results of the achievable potential estimates for solar PV and solar hot water (SHW) by FPL and DEF.

A. DEF and FPL do not provide achievable potential or economic potential for solar resources because their analysis found solar resources are not cost-effective in their jurisdictions.

Q. Please present cost-effectiveness for FPL and DEF's solar pilot programs.

Figure 7.1 presents benefit cost ratios estimated by both companies for their solar PV and solar hot water pilot programs. FPL and DEF proffer that these pilots have benefit cost ratios below 1 under the TRC test.

Figure 7.1 TRC Test Results (Benefit Cost Ratios) of Solar PV Pilot Programs



However, it is highly likely that solar PV and solar hot water could be more cost-effective than the Utilities suggest, as the Utilities do not fully take into account full benefits of demand-side resources and do not assume declining costs of solar PV systems in the future. Secondly, from the utility's perspective using the Utility Cost test, solar PV could be already cost-effective without fully including missed benefits, especially for DEF.

Lastly, note that it is odd that FPL's benefit cost estimates are about half of DEF's estimates for the residential and commercial solar PV pilots. There is a high likelihood that either FPL or DEF are underestimating or overestimating avoided benefits of solar PV systems given that system costs should not differ much between their service territories.

Q. Please explain why the Utilities are not fully taking into account the benefits of solar systems.

A. In a recent meta-analysis of solar PV benefit cost studies, the Rocky Mountain Institute examined 15 studies in detail, and identified that there are numerous benefits of solar PV. This finding indicates that the benefits from solar PV could exceed the costs when benefits are fully considered. For example, four out of the 15 studies found the benefits of solar PV exceeds 20 cents/kWh, and the two of the studies found benefits exceeding about 30 cents/kWh.

The types of benefits identified in the study are (a) avoided energy, (b) avoided generation, transmission and distribution capacity, (c) avoided grid support services (e.g., reactive supply and voltage control), (d) financial risk hedge (e.g., fuel price hedge and market price response), (e) security risk reduction, (f) environmental benefits (e.g., reduction in CO2 and criteria pollutants and water), and (g) economic development (e.g., jobs and tax revenues). FPL and DEF only include benefits from (a) and (b). While they do include some carbon costs in their sensitivity analysis of DSM measures, as discussed above in Section 3, they underestimate carbon costs for complying with future environmental regulations. Further, the Utilities incorrectly assume zero carbon costs in their base case.

Q. Are the costs assumed by the Utilities reflective of forecasts of future PV costs?

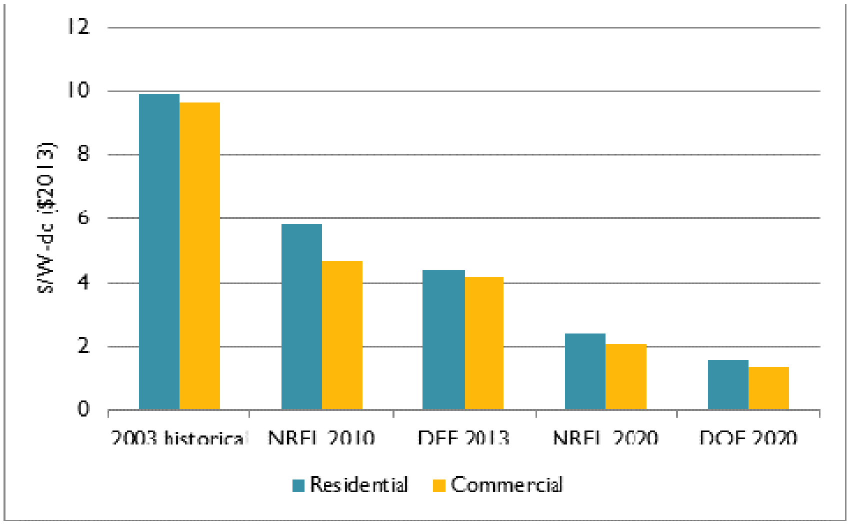
A. No. The Utilities cost-effectiveness results for solar PV are only based on the costs of the current pilot program. *See*, *e.g.*, Direct Testimony of Witness Koch, Document No. 01475-14, at 28–29; Direct Testimony of Witness Guthrie, Document No. 01497-14, at 49 –51. If this is also the case for the formal economic screening, the Utilities are significantly undervaluing the benefits of solar PV for the next decade because price forecasts for PV such those by NREL and US DOE show declining costs.

Q. Please provide solar PV price forecasts by NREL and US DOE and compare them with the current and historical prices.

A. NREL and US DOE have recently developed solar PV price forecasts for the residential and commercial systems. Figure 7.3 provides their price forecasts along with historical prices in 2003, 2010, and 2013. The “DEF 2013” in this figure represents today’s solar PV prices in Florida based on DEF’s data. Direct Testimony of Witness Guthrie, Document No. 01497-14, at 51. Solar PV installed prices have declined by more than half relative to the prices in 2003 as shown in Figure 7.3. Going forward, NREL and

DOE are predicting that solar PV prices will be reduced further by more than half from today's level of $4 per Watt-DC to $2 to $1.5 per Watt-dc levels by 2020.[29]

Figure 7.3 History and Forecast of Installed Costs of Solar PV Systems[30]



US DOE's price forecast represents aggressive price reduction targets under its SunShot Initiative where solar PV prices are reduced by 75% by 2020 from the 2010 levels.[31] In contrast, NREL's price forecast is based on its detailed simulations of silicon module manufacture costs and represents an evolutionary—or business-as-usual—development trajectory for PV prices. NREL indicates that the difference between the evolutionary projections and SunShot targets highlights the need for innovative system designs and installation methods to complement module-level cost reductions.[32]

These low projected installed costs of distributed solar PV systems will result in significantly low levelized costs of solar PV systems by 2020 at levels that are lower than

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[29] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012; US DOE. "SunShot Vision Study." February 2012.

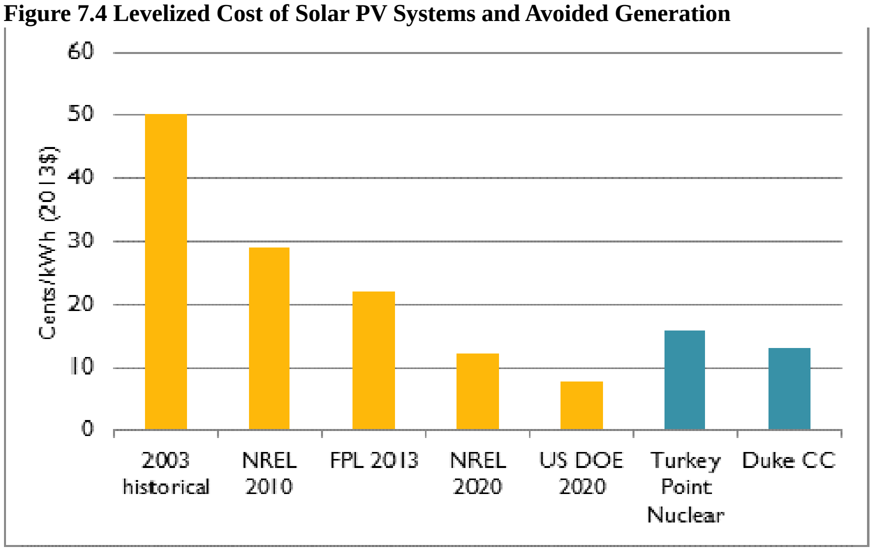
[30] The 2003 historical prices are based on LBNL. "Tracking the Sun VI An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012," July 2013. The "NREL 2010" prices are based on NREL (2012) and represents NREL's simulated historical PV prices used as benchmarking prices to be compared with the NREL's 2020 price forecasts.

[31] US DOE. "SunShot Vision Study." February 2012.

[32] NREL. "Residential, Commercial, and Utility-Scale Photovoltaic (PV) System Prices in the United States: Current Drivers and Cost-Reduction Opportunities," February 2012.

the levelized costs of new nuclear and natural gas combined cycle power plants as presented in Figure 7.4 below.[33] This means that within the Florida Utilities' 10-year planning horizon solar PV is likely to be cheaper and more cost-effective than the traditional supply-side resource options, even excluding the avoided costs of transmission and distribution systems.

Figure 7.4 Levelized Cost of Solar PV Systems and Avoided Generation



<u>**Solar PV Goals**</u>

Q. Please describe the solar PV resource goals proposed by Duke and FPL.

A. Both Duke and FPL did not present any goals for solar PV and proposed to discontinue their demand-side solar pilot programs mainly because they found solar pilot programs are not cost-effective, as shown in Figure 7.1**Error! Reference source not found.** above. In addition, DEF's Witness Guthrie and FPL's Witness Koch question whether the programs' rebates are influencing the market to reduce costs or increasing the availability of solar technologies for customers. *See* Document No. 01497-14, at 51; Document No. 01475, at 30. Further, Witness Guthrie tries to cite the competitiveness of the solar market in Florida as another reason for discontinuing solar rebates and the solar pilot programs

[33] The levelized cost of the residential solar systems are estimated based on (a) the installed costs as presented in Figure 7.3, (b) a 20 year economic life, (c) a 19% capacity factor, and (d) a 5% discount rate. The capacity factor was obtained from NREL's PVWatts for Florida. The levelized costs of Turkey Point nuclear power plants and a combined cycle power plant were taken from Figure 6.2 above in my testimony.

Document No. 01497-14, at 50. More specifically, Witness Guthrie states that Florida's solar market has matured significantly over the last five years, and that Florida is "among the most cost competitive states in the U.S." for solar technologies based on a recent report from Green Tech Media and Solar Electric Industries Association. Document No. 01497-14, at 50

Q. Do you agree with FPL and DEF's proposal to discontinue the solar pilot programs?

A. No. I believe it is premature to discontinue the solar pilot programs, and evidence presented by FPL and DEF to support their position is not compelling for the following reasons:

1. FPL and DEF did not provide compelling evidence for their position nor any study to support their positions. Decisions such as those proposed by the Utilities to discontinue the solar pilot should be based on the results of an independent evaluation similar to the evaluation typically conducted for energy efficiency programs.
2. As discussed in Section 3, the Utilities do not properly account for the benefits of reducing GHG emissions, thereby understating the economic value of the solar pilot programs.
3. Promoting customer-side renewable energy meets FEECA requirements and objectives. FEECA's overall goals are to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, FEECA is specifically designed "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id.*
4. Florida has some of the lowest levels of solar PV installations in the country, despite DEF's claim that Florida is among the most-competitive state for solar.

This indicates that there remains considerable opportunity for more solar installations in Florida.

5. Several other states have aggressive solar PV goals in place that are in effect over the next 5 to 10 years.
6. The cost of solar PV is expected to decline further, and to improve cost-effectiveness of solar PV systems.
7. FPL and DEF haven't provided compelling evidence that solar rebates are not influencing the market, and there is possibility that they could enhance or redesign the solar pilots to increase the program's influence on the market.

Q. How much PV capacity Florida has installed to date, and how does it compare with capacity installed in other states?

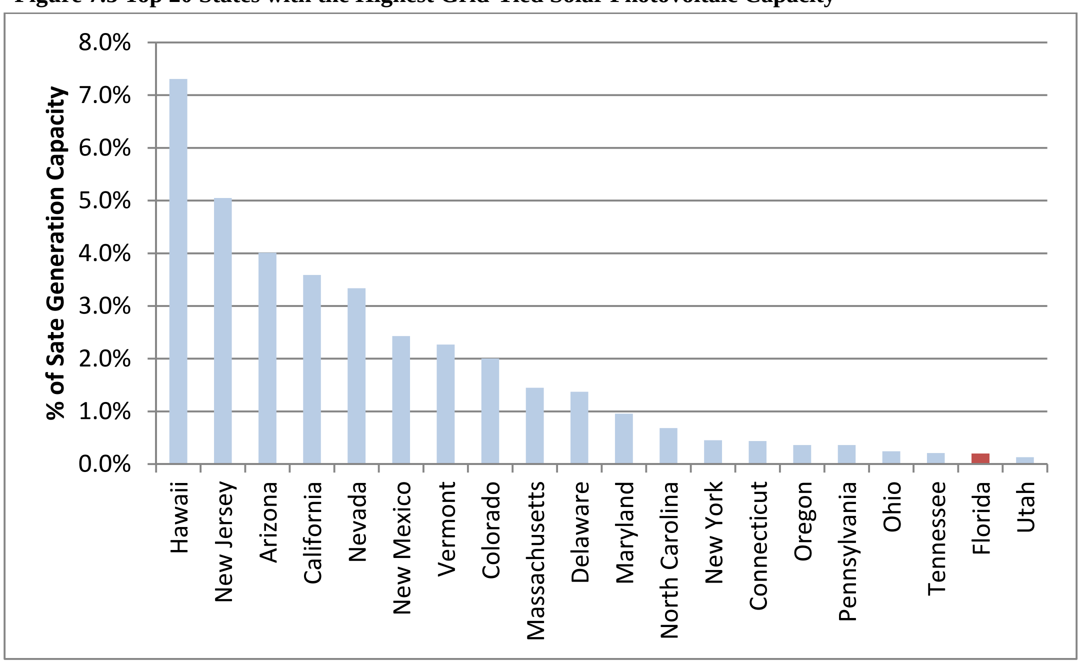
A. Despite the significant amount of solar resource potential in the state and despite DEF's claim that Florida is among the most-competitive state for solar, Florida has installed just about 120 MW of grid connected solar PV as of the end of 2012 according to the Interstate Renewable Energy Council.[34] This ranks Florida 13th in terms of capacity installed in the nation, but ranks 19th in terms of solar PV capacity as a percentage of state total generation. See Table 7.5. As a percentage of state generation capacity, the majority of the top 20 states have installed two to thirty times more solar PV capacity than Florida has installed to date. Note also that more than half of the states with the highest proportion of grid-connected solar photovoltaic capacity to date have less solar resources than Florida. These data imply that Florida's solar market is not competitive, and has not yet matured. Further, the Utilities could and should offer continued, and even more effective support for installations of solar PV.

[34] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013.

Table 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity

Rank	State	Capacity Added in 2012	Cumulative Capacity at the end of 2012	Cumulative Capacity (% of State Generation Capacity)
1	Hawaii	114	200	7.3%
2	New Jersey	391	956	5.1%
3	Arizona	709	1106	4.0%
4	California	983	2559	3.6%
5	Nevada	226	350	3.3%
6	New Mexico	38	203	2.4%
7	Vermont	16	28	2.3%
8	Colorado	103	300	2.0%
9	Massachusetts	123	207	1.5%
10	Delaware	20	46	1.4%
11	Maryland	80	117	1.0%
12	North Carolina	122	208	0.7%
13	New York	56	179	0.5%
14	Connecticut	8	40	0.4%
15	Oregon	21	56	0.4%
16	Pennsylvania	31	164	0.4%
17	Ohio	48	80	0.2%
18	Tennessee	23	45	0.2%
19	Florida	22	117	0.2%
20	Utah	6	10	0.1%

Figure 7.5 Top 20 States with the Highest Grid-Tied Solar Photovoltaic Capacity[35]



[35] Interstate Renewable Energy Council, "U.S. Solar Market Trends 2012," July 2013;US Energy Information Administration, "Electricity Power Monthly," Table 6.2A, January 2014,

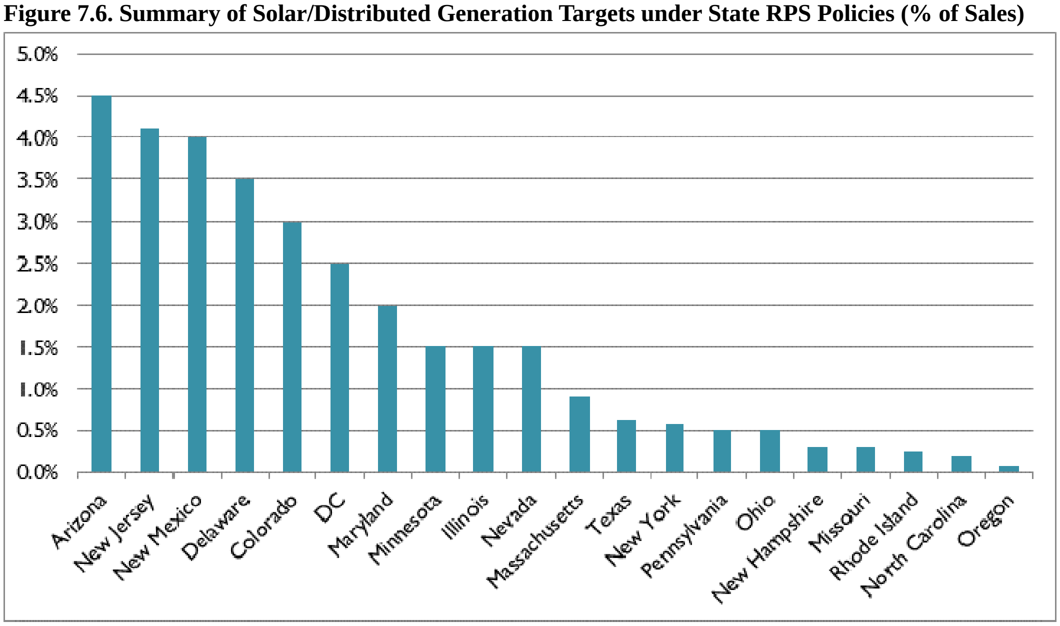
Q. Please describe PV goals established by other states.

A. Across the nation, there are approximately 20 states that require utilities to support the development of solar PV and renewable energy distributed generation systems as part of their renewable energy portfolio standards (RPSs). These states established targets specifically set for promoting either solar system in general (including solar PV and solar hot water), solar PV systems, or distributed generation. **Error! Reference source not found.** 8.6, below, presents a summary of such solar/DG policies along with a normalized target as a percentage increase per year. Figure 7.6 provides just cumulative PV/DG targets. State targets range from 0.1% of sales to 4% of sales in five to fifteen year periods. More than half of the states promote solar/DG at a level exceeding 0.10% per year on average, and 7 states promote solar/DG at more than 0.2% per year on average. In contrast, PV systems installed on FPL and DEF's systems over the past 5 years are very small. Those systems generate about 6 GWh for DEFand 27 GWh for FPL, which are about 0.02% to 0.03% of their 2012 sales or 0.003% to 0.005% per year over a 5 year period or 0.005% to 0.009% per year over a 3 year period (which corresponds to the period of the solar pilot programs).

Table 7.6 Summary of Solar/Distributed Generation Targets under State RPS Policies[36]

State	Technology goal (as % of sales)	Technology	Target Year	% Target per Year of Policy
Arizona	4.50%	DG	2025	0.24%
New Jersey	4.10%	Solar	2027-2028	0.27%
New Mexico	4.00%	Solar	2020	0.31%
Delaware	3.50%	PV	2025-2026	0.23%
Colorado	3.00%	DG	2020	0.30%
DC	2.50%	Solar	2023	0.21%
Maryland	2.00%	Solar	2020	0.15%
Minnesota	1.50%	Solar	2020	0.13%
Illinois	1.50%	PV	2025-2026	0.11%
Nevada	1.50%	Solar	2025	0.09%
Massachusetts	0.90%	Solar	2020	0.13%
New York	0.60%	DG	2015	0.12%
Texas	0.60%	Non-Wind	2020	0.04%
Pennsylvania	0.50%	PV	2020-2021	0.04%
Ohio	0.50%	Solar	2024	0.03%
New Hampshire	0.30%	Solar	2014	0.04%
Rhode Island	0.30%	Solar	2020	0.02%
Missouri	0.30%	Solar	2021	0.02%
North Carolina	0.20%	Solar	2018	0.02%
Oregon	0.10%	PV	2025	0.01%

Figure 7.6. Summary of Solar/Distributed Generation Targets under State RPS Policies (% of Sales)



36 Developed based on information from the DSIRE website, available at http://www.dsireusa.org.

Q. Do you think utility programs could influence Florida's solar PV market? If so, please explain how.

A. Yes. As explained in DEF and FPL's testimony, the number of payback years influence consumer decisions for adopting energy efficiency measures, and customer payback should influence customers' decisions whether to purchase solar PV and Solar Hot Water (SHW) systems. Thus, if the Utilities were to provide some kind of financial support such as rebates or low-interest loans to their customers, such support should increase the number of customers adopting solar systems.

Utility programs could even reduce purchase price of solar systems instantly if the programs could purchase systems in bulk by teaming up with a handful of solar PV installation or marketing companies. Overtime, more installation will develop the solar system installation market in the state, spur competition, and reduce costs.

Q. Should the Utilities continue to offer their solar rebate programs?

A. Yes. These programs are consistent with FEECA's policy goals and provide benefits to participants, as well as system-wide benefits to all customers. FEECA states that "it is critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. Further, it is the intent of "to meet the complex problems of reducing and controlling the growth rates of electric consumption and reducing the growth rates of weather-sensitive peak demand; increasing the overall efficiency and cost-effectiveness of electricity and natural gas production and use; encouraging further development of demand-side renewable energy systems; and conserving expensive resources, particularly petroleum fuels." *Id.* Solar PV systems clearly meet most of these objectives and benefits, and are likely to be cost-effective today if benefits are fully accounted for, and are highly likely to be very cost-effective by 2020 as discussed above in my testimony.

Q. Should Florida utilities modify their rebate program designs?

A. Yes. Florida utilities including Duke and FPL should investigate further whether the current level of incentives is sufficient or excessive to spur solar system development in the state. If they find rebates are excessive, they could consider to what extent rebates should be reduced.

In addition, the utilities should consider offering low-interest loans for solar systems along with reduced level of rebates. In some cases, loans are more helpful than rebates for customers to install solar systems because there are always customers who do not have capital or access to loans.

Lastly, as mentioned above, the utilities should consider coordinating solar system installations by their customers so as to take advantage of bulk purchase practices.

Q. What do you recommend that the Commission do with regard to demand-side renewable goals in this docket?

A. I recommend that the Commission require the Utilities to continue to provide PV programs to their customers, with the modifications to the current programs outlined above. In addition, the Commission should open a separate docket to investigate appropriate additional goals for demand-side renewables, and to address some related issues, e.g., the effectiveness of solar rebate programs and the role of utility-owned solar PV systems.

8. REGULATORY SUPPORT

<u>Treatment of Lost Revenues</u>

Q. Do you think the Utilities should be allowed to recover lost revenues from efficiency programs somehow?

A. Yes. The Utilities should not be penalized financially as a result of successful implementation of efficiency programs. Without recovery of these lost revenues, the Utilities cannot be expected to implement comprehensive, meaningful efficiency programs, their customers will be deprived of the lowest-cost resource, and total electricity costs will be significantly higher.

Q. How should the Utilities recover the lost revenues from DSM programs?

A. I recommend that the Commission require the Utilities to implement a revenue decoupling mechanism to recover the lost revenues from DSM programs. Decoupling is a modification to traditional ratemaking that allows a company to recover a target level of revenues, regardless of the level of sales that occur between rate cases.

Revenue decoupling does not suffer from the fundamental flaws listed above regarding direct recovery of lost revenues. Revenue decoupling provides much more comprehensive and much better financial incentives with regard to all the Utilities' actions that might affect customer sales. I have been involved in several states that use direct recovery of lost revenues as well as several states that use revenue decoupling, and the difference is striking. Utilities that are allowed revenue decoupling are significantly more supportive of DSM and other demand resources, and the entire regulatory context around efficiency and demand resource planning is significantly less contentious and adversarial. Further, there are ways to design revenue decoupling mechanisms that not only protect consumers but ensure that customers are better off than under traditional ratemaking.

If the Commission does not somehow address the recovery of lost revenues, then it is very likely that the Utilities will continue to understate the value of DSM, propose sub-optimal DSM goals, and deprive customers of the opportunity to significantly reduce their electricity bills.

Q. Has the issue of decoupling been addressed before by the Commission?

A. Yes. In December 2008 the Commission prepared a report to the Legislature on utility revenue decoupling. FPSC, *Report to the Legislature on Utility Revenue Decoupling* (Dec. 2008), *available at* http://www.psc.state.fl.us/publications/pdf/electricgas/Decoupling Report_To_ Legislature.pdf. At that time, the Commission decided not to implement revenue decoupling, because "Florida is already paving a path toward the objectives of decoupling without incurring the cost and difficulties associated with design, implementation and maintenance of a specific decoupling mechanism." *Id*. at 5.

Q. Is there evidence in the current dockets that the Utilities are paving a path toward more comprehensive implementation of cost-effective DSM programs?

No. In fact, the evidence presented in these dockets suggests the opposite. As described in Section 6, the Utilities' DSM programs are already much smaller than those of most other states, and the DSM goals proposed in these dockets would essentially take the Utilities on a path of less and less DSM. In addition, the Utilities' analyses in these dockets are so clearly heavily biased against DSM programs, that one can only conclude that the Utilities really do not want to implement DSM programs and achieve DSM savings for their customers. This is quite likely due to the financial disincentive associated with DSM programs. A revenue decoupling mechanism would eliminate this disincentive, and create a much more positive regulatory environment for setting future DSM goals.

Q. How should the Commission proceed on this issue of decoupling?

A. I recommend that the Commission open a separate docket to investigate whether revenue decoupling should be implemented to align the Utilities' financial incentives with the state's efficiency policies and goals. There are many important implications of revenue decoupling, and the issues are best addressed in a docket dedicated to investigating them.

<u>Shareholder Incentives</u>

Q. Why is it necessary to provide utilities with shareholder incentives for implementing DSM programs?

A. While decoupling is necessary to eliminate the financial disincentive that utilities experience with efficiency, it does not provide utilities with positive financial incentives. When given the choice between investments in supply-side resources, which can be included in rate base and contribute toward utility profits, and investments in DSM that are simply passed through to customers, utilities will prefer the former.

Q. Does the Commission have authority to provide the Utilities with shareholder incentives for implementing successful DSM programs?

A. Yes. The recent amendments to FEECA allow the Commission to "authorize financial rewards for those utilities over which it has ratesetting authority that exceed their goals and may authorize financial penalties for those utilities that fail to meet their goals." Section 366.82(8), F.S. Further, FEECA is to be liberally construed. *See* Section 366.81.

Q. Is it necessary that DSM programs be included in rate base in the same way that supply-side resource are?

A. No. The two investments have different financial and ratemaking implications, and thus do not need to be treated identically for shareholder incentive purposes. What is important is that the DSM shareholder incentives be: (a) large enough to provide the utility management with the incentive to pursue DSM programs; and, (b) designed in a way that encourages the implementation of cost-effective, successful DSM programs that are in the customers' best interests. It is also important to keep the shareholder incentives reasonably low, so that customers are not required to pay more than necessary for a utility to implement successful DSM programs.

Q. What type of shareholder incentive mechanism would you recommend to achieve these objectives?

A. Here I summarize an DSM shareholder incentive mechanism that the Commission should establish:

- A utility will have the opportunity to earn a maximum of eight percent of its total annual DSM budget as a shareholder performance incentive. The amount of this total incentive that each utility earns will depend on what portion of its efficiency savings target it achieves, as prescribed below.
- A utility will not be allowed to earn any shareholder incentive until it achieves at least 80 percent of its annual efficiency savings goal.
- If a utility achieves 80 percent of its annual efficiency savings goal, it will be entitled to keep four percent of the annual efficiency budget as a shareholder incentive
- If a utility achieves 100 percent of its annual efficiency savings goal, it will be entitled to keep six percent of the annual efficiency budget as a shareholder incentive.
- If a utility achieves 120 percent of its annual efficiency savings goal, it will be entitled to keep eight percent of the annual DSM budget as a shareholder incentive.

- If a utility achieves efficiency savings that are between 80 percent and 120 percent of its annual efficiency savings goal, it will be entitled to keep an portion of the annual DSM budget determined by linear interpolation between four and eight percent.
- Shareholder incentives will only be allowed for DSM program savings that are measured and verified and presented to the Commission in annual reports.

Q. How should the Commission proceed on this issue of shareholder incentives?

A. I recommend that the Commission consider the issue of shareholder incentives in the same generic docket that it uses for investigating revenue decoupling. Like decoupling, shareholder incentives require consideration of some important details, and most of the issues should be relevant to all Florida utilities. A single generic docket would allow the Commission to address both revenue decoupling and shareholder incentives in a comprehensive way.

Q. Does this conclude your pre-filed testimony?

A. Yes, it does.

BY MS. CSANK:

Q Mr. Woolf, do you have a summary of your testimony?

A Yes, I do.

Q Please give your summary.

A Thank you. Good morning, Mr. Chair, Commissioners.

I want to summarize three key points in my testimony: First, energy efficiency is good for customers; second, energy efficiency is abundant and highly cost-effective; and, third, the Sierra Club goals are reasonable, feasible, and appropriate.

When I say the energy efficiency programs are good for customers, I mean all customers, participants and non-participants alike. All customers experience some of the benefits of DSM, including deferred or avoided new power plants, reduced transmission and distribution costs, improved system reliability, reduced risks, and reduced environmental compliance costs.

It is true that program participants experience additional benefits above and beyond the non-participants, but it's critical to recognize that energy efficiency offers benefits even to the non-participants.

Nonetheless, the companies can serve a large portion of customers with their DSM program, thereby spreading the benefits around and mitigating concerns about customer inequities. For example, in Florida Power & Light's annual DSM reports they indicate that if the company had continued with the goals that they had as of February this year, they could reach over 40 percent of residential customers and over 70% of C&I customers over the course of ten years. This is in addition to all the customers that they've served already over the past 20 to 30 years. This is a very large portion of customers who see direct and immediate benefits of the energy efficiency programs. Unfortunately, the companies' proposed goals would limit customer participation and deny many the ability to reduce their bills through DSM programs.

Participation in DSM programs is particularly important for a variety of customers that face barriers to DSM and would benefit enormously from efficiency measures. These include low income customers, elderly customers on fixed incomes, residential customers whose incomes don't necessarily qualify as low income by federal poverty standards or whatever standard but who still struggle economically, and by small businesses that operate day to day with tight margins. These types of customers are simply not in the position to implement many DSM measures for a variety of reasons, even measures with short payback periods. These are the customers that are most in need of assistance from DSM measures, and yet these are the very customers that the utilities are shutting out of their programs with their extremely low program goals and their assumptions regarding free ridership.

My second point, energy efficiency is highly cost-effective. FEECA is very clear that the Commission's goal setting must consider program participants and the body of ratepayers as a whole. However, the utilities' proposed goals are based entirely on rate impacts, without giving the Commission meaningful information to consider on how program participants and the body of ratepayers benefit from DSM. They're ignoring this key piece of information that's critical to meeting the FEECA requirements. The utilities' proposed goals also violate the Commission's rule calling for goals that reflect results of the TRC test and the Participant test.

To make matters worse, the utilities' estimates of rate impacts are dramatically overstated. First, their estimates assume that there will be a rate case every year. In fact, for every year where there is no rate case, the base rates will not increase as a result of energy efficiency. So if there's no rate case for, say, four years, then the rate impacts will be one-quarter of what the company has estimated.

Second, the utilities assume that rates will have to be increased to recover both fixed and variable cost when, in fact, the rates don't have to be increased to recover variable costs because the variable costs are avoided through the energy efficiency. Given that variable costs can be as much as a half a percent, I mean, I'm sorry, 50 percent, half of customers' costs, customers' rates, this one assumption can result in a doubling, erroneously doubling rate impacts.

A better analysis would show that the rate impacts of energy efficiency would be very low and that these rate impacts would be outweighed by the many customer benefits of efficiency.

My final point, the Sierra Club goals are reasonable, achievable, and they're appropriate for Florida. The Sierra Club recommends the Commission set an annual energy savings goal of 1 percent of retail sales by 2019. This is a modest goal. It is very reasonable, very achievable, and it reflects Florida's historical experience with energy efficiency. The evidence in this docket indicates that there is significantly more efficiency available in Florida than what is included in the utilities' goals and that this additional DSM is cost-effective.

Furthermore, many states have achieved this level of efficiency savings already. Many states have higher DSM goals, and some states have goals that are twice as high as what's being proposed here -- I'm sorry -- twice as high as the Sierra Club goals, even though those states face the same conditions that the utilities here do in terms of lower avoided cost and increased building codes and efficiency standards.

In conclusion, there's no question that customers would benefit from the Sierra Club goals in terms of reduced electricity cost, increased customer participation, reduced bills, and reduced risk.

Thank you. I look forward to your questions.

MS. CSANK: Mr. Chairman, Mr. Woolf is available for cross-examination.

CHAIRMAN GRAHAM: Thank you. Top of the list, OPC.

MR. SAYLER: Good morning, Mr. Chairman. No questions.

CHAIRMAN GRAHAM: Department of Agriculture.

MR. HALL: No questions.

CHAIRMAN GRAHAM: NAACP.

MR. DREW: No questions.

CHAIRMAN GRAHAM: FIPUG.

MR. MOYLE: I have just a couple of questions.

EXAMINATION

BY MR. MOYLE:

Q Good morning, sir. I'm Jon Moyle with the Florida Industrial Power Users Group.

Does the Sierra Club support cross-subsidization when establishing energy efficiency goals? If you could answer yes, no, I'd appreciate it.

A No. I would not describe the Sierra Club goals or my recommendations as supporting cross-subsidization as such.

MR. MOYLE: Okay. Thank you. That's all I have.

CHAIRMAN GRAHAM: SACE.

MS. TAUBER: No questions, Mr. Chairman.

CHAIRMAN GRAHAM: EDF. I guess EDF has no questions.

Okay. Florida Power & Light.

MR. BUTLER: No questions, Mr. Chairman.

CHAIRMAN GRAHAM: Duke.

MS. TRIPLETT: No questions.

CHAIRMAN GRAHAM: TECO.

MR. BEASLEY: No questions.

CHAIRMAN GRAHAM: Gulf.

MR. GRIFFIN: No questions.

CHAIRMAN GRAHAM: Staff.

MS. CORBARI: Staff has a few questions.

CHAIRMAN GRAHAM: Okay.

EXAMINATION

BY MS. CORBARI:

Q Good morning, Mr. Woolf. Kelley Corbari, Commission Staff.

I just have a couple of questions for you this morning. If you could please turn to your direct testimony, page 97, starting at line 12 through page 98, which includes Table 7.5 and Figure 7.5, and then page 100, Table 7.6. If you'll let me know when you get there.

A I have that in front of me, yes.

Q Okay. Table 7.5 illustrates the top 20 states with the highest grid-tied solar photovoltaic capacity, and Table 7.6 is a summary of generation targets for states with renewable energy portfolio standards.

Comparing Table 7.5 and 7.6, would you agree that a majority of the 18 states with more solar generation than Florida have a renewable energy portfolio standard?

A I have not checked that, but, subject to check, I would not be surprised to hear that.

Q So subject to check, you would agree that 13 of the 18 states listed on 7.5 with more solar generation than Florida are also listed on 7.6?

A Yes.

Q Thank you. Do you believe decision-makers should consider the potential increase in the price of electricity that ratepayers may incur as a result of energy policy decisions?

A Yes. I think that rate impacts are very important in these decisions, and they need to be considered with meaningful comprehensive analyses of the -- to rate impacts of whether it's energy efficiency or photovoltaic resources.

Q When making your analysis, did you consider the price per kilowatt hour of electricity in states that have more solar capacity as a percentage of state total generation as compared to the price of per kilowatt hour in Florida?

A I'm aware that the states have very different prices. I did not do a comprehensive analysis of each of the prices in each of the states.

Q Okay. A couple more questions. Please turn to page 101 of your direct testimony, starting at line 28 through line 8 on page 102.

A Yes.

Q Here you're recommending that Florida utilities modify rebate, their rebate program designs. Are you aware of any studies conducted using data from Florida to determine the optimal incentive needed to encourage the development of demand-side renewable energy resources?

A I'm not. That's exactly the kind of studies that the company should undertake to figure out the best way to use the funding available for PV.

Q Last question. Do you believe the current rebate level for solar PV of $2 per installed watt is excessive?

A I haven't done a thorough analysis of what the optimal rebate level is, but, based upon the evidence in this docket and what I've seen, it does seem to be on the high side, given how quickly customers are picking it up.

I think, as I suggest here, that there may be other ways to use the money available for PV more efficiently than providing such high rebate levels.

MS. CORBARI: Thank you, Mr. Woolf. Staff has no more questions.

CHAIRMAN GRAHAM: Thank you, staff.

Commissioners. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman.

And thank you, Mr. Woolf. And I want to congratulate you; I think you have the record. Your testimony encompasses an entire binder. I think that's a first, at least for me. I don't know if Commissioner Edgar has had that experience.

I just have one question, really a clarification on what -- a comment you made during your summary. You indicated that there's information available that indicates that if the current goals remain in place, there will be a larger percentage of customers being reached. And I just want to clarify, do you mean the current goals or the current DSM programs that are in place?

THE WITNESS: I drew that information from the company's annual reports, in this case Florida Power & Light's, and I have -- if you'll give me just a minute -- a couple of graphs that present that information. I'm pretty sure I have it marked here. Oh, I know where I can find it. Give me just a moment.

On page 70 of my testimony I present two figures, cumulative participation rates for residential programs and cumulative participation rates for commercial and industrial programs. This data is taken directly from the company's, FP&L's annual reports, where they report historic savings and participation rates, and they also present a forecast of what the participation rates would be like if they were to continue on the path of the programs at that time.

COMMISSIONER BALBIS: Okay. And I understand that and I was clear on your testimony, but you stated if we continue with the current goals and the plans that the Commission -- that the utilities modified were to match their existing programs on the previous goals. So your testimony indicates that if they continue with their current programs, they would reach this number of customers, not the goals which they do not have plans to meet.

THE WITNESS: I think I'm confused by your question. Just to be clear, the information here is straight from the annual reports that the utilities prepare where they project participation rates based upon their understanding of their current programs and where they may go. I think I'm a little confused by when you say the current goals. There are no goals currently for 2015 through 2019.

COMMISSIONER BALBIS: Correct.

THE WITNESS: Okay.

COMMISSIONER BALBIS: Correct. But these programs -- the Commission set goals in 2009, and then the utilities modified the plans to match their current programs. And so your data seems to indicate that if they continue with their current programs regardless of the goals, that these are the customers they would reach.

THE WITNESS: Yes.

COMMISSIONER BALBIS: Okay. That's the only clarification I needed. Thank you.

CHAIRMAN GRAHAM: Commissioner Brown.

COMMISSIONER BROWN: Thank you.

Good morning, Mr. Woolf. I believe this is your first time testifying before the Florida Public Service Commission.

THE WITNESS: It is.

COMMISSIONER BROWN: Okay. You provide in your prefiled testimony, you recommend to us to open a separate docket to investigate goals for customer-sited renewables; correct?

THE WITNESS: Yes.

COMMISSIONER BROWN: Can you elaborate?

THE WITNESS: Yeah. In fact, it's based upon the question that we just got from staff a little while ago. Their, you know, their -- the utilities' pilot programs do raise some concerns about how effectively the utilities are using the funding that they have available for photovoltaics and other solar measures.

So I don't see in this docket enough evidence to suggest how to improve those to make sure that they're used most efficiently in the future. So a separate docket would consider things like how should funding for PV be used to motivate those customers that wouldn't otherwise be installing PV. And it could include alternative ways of financing, it could include alternative ways of tapping into market forces to help promote PV. The utilities could put forth a certain amount of funding and allow vendors to compete to provide the lowest cost photovoltaic systems, you know, given that amount of money available. So you use a whole lot more creative options for achieving the goals here without simply throwing away the pilots or the whole concept.

COMMISSIONER BROWN: Thank you very much.

CHAIRMAN GRAHAM: Any other Commissioners?

Redirect?

MS. CSANK: No redirect, Mr. Chairman.

CHAIRMAN GRAHAM: Okay. Let's take up exhibits.

MS. CSANK: Sierra Club moves to enter exhibits, hearing Exhibits 81 to 93.

CHAIRMAN GRAHAM: We'll enter exhibits 81 through 93 into the record.

(Exhibits 81 through 93 admitted into the record.)

Mr. Woolf, thank you for your testimony.

Okay. So we are now circling around to rebuttal witnesses, and back to the top of the list, Florida Power & Light.

MR. BUTLER: Thank you. Yes. FPL would call, for his rebuttal testimony, Terry Deason.

MR. DONALDSON: Good morning, Mr. Chairman and Commissioners.

Whereupon,

TERRY DEASON

was called as a witness on behalf of Florida Power & Light Company and, having first been duly sworn, testified as follows:

BY MR. DONALDSON:

Q Good morning, Mr. Deason.

A Good morning.

Q Have you been previously sworn?

A Yes, I have.

Q Have you prepared and caused to be filed 41 pages of rebuttal testimony in this proceeding on June 10th, 2014?

A Yes.

Q Do you have any changes or revisions to your rebuttal testimony to make at this time?

A No.

Q If I were to ask you the same questions contained within your rebuttal testimony today, would your answers be the same?

A Yes.

MR. DONALDSON: Mr. Chairman, FPL asks that Mr. Deason's rebuttal testimony be inserted into the record as though read.

CHAIRMAN GRAHAM: We will enter Mr. Deason's rebuttal testimony into the record as though read.

MR. DONALDSON: Thank you.

BY MR. DONALDSON:

Q Does your rebuttal testimony consist of an exhibit entitled JTD-3?

A Yes.

Q And you are sponsoring that exhibit to your testimony?

A Yes.

Q Is that exhibit true and correct to the best of your knowledge?

A Yes.

Q I would note that this exhibit has been premarked for ID, on staff's comprehensive list, Number 150.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

REBUTTAL TESTIMONY OF J. TERRY DEASON

DOCKET NO. 130199-EI

JUNE 10, 2014

Q. Please state your name and business address.

A. My name is Terry Deason. My business address is 301 S. Bronough Street, Suite 200, Tallahassee, FL 32301.

Q. Have you previously submitted direct testimony in this proceeding?

A. Yes.

Q. Are you sponsoring any rebuttal exhibits?

A. Yes. I am sponsoring Exhibit JTD-3: Residential Retail Rate Comparison.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to many of the positions and recommendations contained in the testimony of Southern Alliance for Clean Energy (SACE) witness Natalie A. Mims and the testimony of Sierra Club witness Tim Woolf. Both of these witnesses liberally criticize a number of precedents and policies that have been traditionally and successfully used in Florida to set appropriate Demand Side Management (DSM) goals in compliance with the Florida Energy Efficiency and Conservation Act (FEECA), Rule 25-17.0021, F.A.C., and decisions of the Florida Supreme Court. Their criticisms are unfounded and their recommendations are inappropriate, unnecessary, contrary to Florida statutes and rules, and not adequately substantiated by the evidence presented. In essence, their mission is to pressure the Commission into embarking on a never before taken path to inappropriately and arbitrarily increase DSM goals.

Q. How is your rebuttal testimony organized?

A: My rebuttal testimony is organized into eight sections. Section I addresses cost-effectiveness and the intervenor witnesses' ill-advised suggestion to use the Total Resource Cost (TRC) test to the exclusion of the Rate Impact Measure (RIM) test and its role of minimizing rate impacts and cross-subsidies. Section II addresses cross-subsidizations and the intervenor witnesses' unfounded assertions that cross-subsidies can and should be disregarded when setting conservation goals. Section III addresses the intervenor witnesses' incorrect assertion that bill impacts must take precedence over rate impacts. Section IV addresses free-riders and the intervenor witnesses' recommendation to abandon the Commission's two-year payback screening criterion. Section V addresses the concept of external costs and benefits and the intervenor witnesses' attempt to use them to inappropriately increase DSM goals. Section VI addresses the intervenor witnesses' overarching and misapplied contention that other states' DSM approaches prove that Florida's policies and approaches are inappropriate or somehow do not protect the customers' best interests. Section VII addresses goals for demand-side renewable energy systems. Section VIII is my conclusion.

I. COST-EFFECTIVENESS

Q. What has been the Commission's policy regarding cost-effectiveness determinations within FEECA?

A. The Commission has had a long history of implementing FEECA in a manner that works to minimize rate impacts on all customers and prevent cross-subsidizations among customers. The Commission has relied primarily on the RIM test in order to help ensure these results. This approach has served FPL's customers well for decades -- FPL has achieved significant cumulative DSM savings while keeping customer electric rates low.

In 2009, the Commission tested another approach by using the TRC test to set FPL's goals. When the electric rate impacts to customers of this approach (and other modifications to Commission policy) were recognized in the course of reviewing FPL's DSM Plan for implementation, the Commission ultimately decided the rate impacts resulting from the TRC test were too high. Rather than continuing down the path set by the 2009 DSM goals docket, the Commission required FPL to implement DSM programs that had been determined to be cost-effective under the RIM test in a previous DSM proceeding.

Q. **Do witnesses Mims and Woolf believe that the Commission has discretion to use the RIM test to set goals?**

A. Apparently, no. Despite the Commission's historical use of RIM and the plain language of Rule 25-17.008, F.A.C., which references the Florida Public Service Commission Cost Effectiveness Manual, witness Mims states that FEECA mandates that utilities use the TRC test. In addition, she states that the issue of RIM vs. TRC is a moot issue: "The Commission already determined what test to rely on in the last energy efficiency goals proceeding, and it is the Total Resource Cost test." Witness Woolf does not directly state that FEECA mandates the use of the TRC test. However, he strongly implies such when he criticizes the RIM test as not meeting the statutory requirements of Section 366.82(3), F.S. By his testimony, he would apparently remove the Commission's discretion to use the RIM test to set goals.

Q. Did the Commission's decision in 2009 DSM goals proceeding make the issue of which cost-effectiveness test to use moot?

A. No. While the Commission did vote to use the TRC test in the last goal setting proceeding, it ultimately decided to not approve programs for FPL based on TRC, choosing instead to continue programs that were previously approved based on the RIM test. And before the Commission's use of TRC in the last goal setting proceeding, the Commission consistently used the RIM test in every goal setting proceeding since 1994 and likewise approved programs that passed the RIM test. Furthermore, the Commission's rules require the filing of cost-effectiveness data on all the tests contained in its Cost Effectiveness Manual and do not declare the use of one test to the exclusion of another.

Q. Does the Commission have the discretion to use the RIM test to set goals?

A. Yes, absolutely. In their narrowly focused zeal to have the Commission summarily reject the RIM test and instead use the TRC test, Witnesses Mims and Woolf misinterpret Section 366.82(3) and ignore, or at least minimize, another important statutory requirement.

Q. Please explain.

A. Both witnesses Mims and Woolf emphasize the provision in Section 366.82(3) to consider "The costs and benefits to the general body of ratepayers as a whole" to incorrectly conclude that this requires the use of the TRC test. However, a close examination of the regulatory meaning of this phrase reveals that this statutory provision is actually more supportive of using the RIM test rather than the TRC test.

Q. What is the regulatory meaning of this phrase which leads you to conclude that it supports the use of the RIM test?

A. In Florida, the phrase "costs and benefits to the general body of ratepayers as a whole" has its roots in determining rates that are fair and which do not pit the interests of one group of customers against those of another, which in turn could result in cross-subsidies. Its application results in the protection of all customers as a whole.

A good example of this is Florida's policy concerning customer deposits. This policy helps protect customers as a whole from the costs and risks imposed by those customers who have not established a good pattern of consistent on-time payments. These customers are required to pay a deposit. To protect those customers who must pay a deposit and to avoid an unfair benefit to the general body of customers, interest is required to be paid on the deposits. Thus, both groups of customers (i.e., those who must post deposits and those who do not) are treated fairly because they do not have to subsidize each other. Another example is that those customers which choose underground service are required to pay the incremental costs of providing that service. This protects the general body of customers from having their rates increased to cover the costs of those choosing underground service. In the context of DSM goals, it is only the RIM test which protects the general body of customers by not having rates increased for all customers. The RIM test does this by recognizing lost revenues and the cost of incentives. The TRC test ignores both the impact on rates of lost revenues and the impact on rates of incentives. Therefore, the TRC test is ill equipped to consider the impacts on the general body of customers as a whole, as the statute requires.

Q. Did the Commission consider this statutory provision in the last goal setting proceeding?

A. Yes. This provision, on which witnesses Mims and Woolf so steadfastly rely in maintaining that TRC should be used to the exclusion of RIM, was added to FEECA in 2008. Since this provision was new at the time of the last goal setting proceeding, the Commission addressed whether it fundamentally changed matters which it had historically considered and whether it required the use of the TRC test, as a witness for SACE was then contending.

Q. What did the Commission decide?

A. The Commission rejected SACE's position and in its Order No. PSC-09-0855-FOF-EG stated: "We would note that the language added in 2008 did not explicitly identify a particular test that must be used to set goals."

Q. Do you agree with the Commission's determination?

A. Yes, I definitely do. I would also add that while the specific statutory language at issue is relatively new, the standard it clearly establishes is not new for the Commission. The Commission's historical use of the RIM test (coupled with the Participant Test) has been firmly rooted in its concern for the general body of customers. This is evidenced by the fact that the RIM test is best suited to account for the cost of incentives, to minimize rate impacts, and to avoid subsidies between participating and non-participating customers.

Q. In response to a previous question, you stated that witnesses Mims and Woolf do not adequately consider another important statutory provision. To what statutory provision do you refer?

A. I am referring to Section 366.81, F.S. which gives direction to the Commission in setting conservation goals and the utilization of the most efficient and cost-effective demand-side renewable energy systems and conservation systems. This statutory provision goes on to give specific instruction to the Commission on the rate impacts of its decisions: "Accordingly, in exercising its jurisdiction, the Commission shall not approve any rate or rate structure which discriminates against any class of customers on the account of the use of such facilities, systems, or devices."

Q. How has the Commission applied this statutory requirement?

A. The Commission has historically set conservation goals with the objective of protecting all customers from higher rates and minimizing cross-subsidies between participants and non-participants in approved conservation programs. This was accomplished by primary reliance on the RIM test. The Commission also recognized that the use of the TRC test could result in cross-subsidies between customers and could disproportionately impact low-income customers. In its Order No. PSC-94-1313-FOF-EG, the Commission stated:

> We will set overall conservation goals for each utility based on measures that pass both the Participant and RIM tests.... We find that goals based on measures that pass TRC but not RIM would result in increased rates and would cause customers who do not participate in a utility DSM measure to subsidize customers who do participate.
>
> ***
>
> All customers, including low-income customers, should benefit from RIM-based DSM programs. This is because RIM-based programs ensure that both participating and non-participating customers benefit from utility-sponsored conservation programs. Additional generating capacity is deferred and the rates paid by

low-income customers are less than they otherwise would be.

Q. You just quoted a 1994 Commission order. Has the Commission more recently addressed the need to minimize cross-subsidies between participants and non-participants?

A. Yes, in its Order No. PSC-09-0855-FOF-EG, the Commission acknowledged that FEECA requires consideration of impacts on participants and non-participants: "FEECA makes it clear that we must consider the economic impact to all, both participants and non-participants." In this same Order, the Commission went on to recognize that the TRC test could negatively impact non-participants: "Those who do not or cannot participate in an incentive program will not see their monthly utility bill go down unless they directly decrease their consumption of electricity. If that is not possible, non-participants could actually see an increase in their monthly utility bill."

Q. Has the Florida Supreme Court addressed the need to consider cross-subsidies in setting conservation goals?

A. Yes. In an appeal by the Legal Environmental Assistance Foundation (LEAF) of a Commission order setting goals using the RIM test, the Court rejected LEAF's arguments that the TRC test should have been used. The Court stated:

> In instructing the Commission to set conservation goals for increasing energy efficiency and conservation, the legislature directed the Commission to not approve any rate or rate structure which discriminates against any class of customers. See § 366.81, Fla. Stat. (1993). The Commission was therefore compelled to determine the overall effect on rates, generation expansion, and

revenue requirements. Based on our review of the record, we find ample support for the Commission's determination to set conservation goals using RIM measures. Accordingly, we affirm the orders of the Commission.

Legal Environmental Assistance Foundation Inc. v. Clark, 668 So.2d 982 (Fla. 1996).

II. CROSS-SUBSIDIZATIONS

Q. Do witnesses Mims and Woolf address the issue of cross-subsidization?

A. Yes, and to their credit they generally acknowledge that cross-subsidies should be avoided where possible. However, beyond that mere acknowledgement, they are dismissive of cross-subsidization concerns when it comes to setting conservation goals. In fact, it is witness Mims' contention that the discussion of cross-subsidization with respect to the setting of DSM goals is moot and/or irrelevant.

Q. In what way does witness Mims declare cross-subsidies to be moot or irrelevant?

A. She theorizes that if sales were to decline significantly as a result of energy efficiency, there would have to be a large number of participants and fewer non-participants, making cross-subsidization irrelevant.

Q. Do you agree with her theory?

A. I do not agree for several reasons. First, she once again ignores the clear language of Section 366.81, F.S., as cited by the Florida Supreme Court in the LEAF appeal I just referenced. The Commission does not have the option to simply declare this statutory requirement to be irrelevant. Second, her contention is not factually supported. At best, it is at some level intuitively appealing. However, it is not factually true that a high level of energy efficiency means that the vast majority of customers are participants as opposed to being non-participants. Such an outcome would be dependent on the amount of savings achieved by what mix of customers. It is equally plausible that larger users which would be eligible for a higher number of programs could cause the bulk of the costs and the incurrence of most of the lost revenue. Third, and most importantly, the issue of cross-subsidization is not as simple as taking a census of the number of participants versus non-participants. This would be tantamount to saying that it is okay to discriminate against the minority because the majority is receiving the benefits. In fact, as the proportion of non-participants declines, the burden of cross-subsidization falls more and more heavily on those who remain.

Q. Are there other ways in which witnesses Mims and Woolf attempt to marginalize concerns over cross-subsidies?

A. Yes, both witnesses Mims and Woolf state that cross-subsidies are endemic to regulated electric utilities, implying that it is okay to promote cross-subsidies when setting conservation goals. This is merely a thinly veiled excuse to engage in an activity that has negative consequences for customers.

Q. Are cross-subsidies endemic to regulated electric utilities?

A. No, "endemic" connotes a certain degree of pervasiveness and inevitability, which is simply inaccurate. Regulation in Florida goes to great lengths to set rates which are fair, just, and reasonable and which do not foster cross-subsidies between customers. This is apparent in both the nature of and the extent to which costs are recognized in rates, as well as in the structure of the rates themselves. The Commission has rules dealing with cost of service studies and many years of precedent to ensure that rates are set equitably and on a non-discriminatory basis. The Commission also has a policy of having cost causers pay their fair share of the costs they place on the system, especially when they engage in actions or chose options which, if not specifically recognized, would cause rates for the general body of customers to increase. All of this is done to minimize cross-subsidies to the greatest extent possible.

Q. Doesn't witness Woolf give a series of examples of what he claims are endemic cross-subsidies?

A. He provides a series of examples which he claims show that cross-subsidies are endemic. However, I disagree that his examples stand for that proposition. He presents hypothetical cases in which increased investments in generating, transmission, or distribution facilities are designed to benefit only a few customers. This is not consistent with the way that Florida plans and approves investments as part of a coordinated grid, subject to the Commission's Grid Bill authority. It is generally understood that increased investment in the grid as a whole benefits all customers, who then must pay for them according to the cost of service studies and cost allocations consistent with the rate class in which they take service. I do agree that there is a necessary level of averaging between customers of the same class and that someone could argue, at some esoteric theoretical level, that there is some cross-subsidization that remains at a very granular level. But this simply attempts to confuse the practical with the perfect.

This is the important point: it is not the goal of regulation to intentionally make policy decisions that knowingly will result in cross-subsidies or increase some theoretical level of innate subsidies that could be argued to exist. To the contrary, it is the goal of regulation to prevent cross-subsidies whenever possible and the Florida Commission makes every reasonable effort to do so. It would be bad public policy to intentionally engage in an action that knowingly results in cross-subsidies. However, this is exactly what witnesses Mims and Woolf would have the Commission do. They would have the Commission adopt a cost-effectiveness test and DSM goals resulting from its application that will knowingly result in cross-subsidies between participants and non-participants.

Q. Has the Commission recognized that increased rates and cross-subsidies could result from use of the TRC test?

A. Yes, in addition to the language in Order No. PSC-09-0855-FOF-EG which I earlier referenced, the Commission also specifically recognized that the TRC test does not account for lost revenues: "Because the TRC Test excludes lost revenues, a measure that is cost-effective under the TRC Test would be less revenue intensive than a utility's next planned supply-side resource addition. However, the rate impact may be greater due to reduced sales."

Q. Doesn't witness Woolf criticize the manner in which the utilities calculate the amount of lost revenues under the RIM test?

A. Yes, he states that the estimation of bill impacts from lost revenues is inconsistent with the way rates are set in Florida. He observes that base rates are only increased at the time of a rate case and asserts that any lost revenue between rate cases should be ignored.

Q. Is he correct?

A. He is correct that the impact of lost revenues is a part of base rates and would be recovered as part of a rate case. However, he is incorrect that lost revenues can be dismissed because there is a delay in the time the revenues are lost and the time that rates can be increased to account for them. Such a phenomenon is referred to as regulatory lag.

Q. Does Florida have a policy concerning regulatory lag?

A. Yes. Both the Florida Legislature and the Florida Supreme Court have recognized regulatory lag as being counter to the goals of good regulatory policy. The Florida Legislature has given tools to the Commission to minimize regulatory lag and these tools have been sustained by the Florida Supreme Court. Floridians United for Safe Energy, Inc. v. Public Service Commission, 475 So. 2d 241 (Fla. 1985). And the Commission has used these tools to minimize the harmful effects of regulatory lag.

Q. Is this relevant to the setting of conservation goals?

A. Yes, it is very relevant. It would be counter-intuitive and counter-productive to have a policy of reducing regulatory lag in the setting of base rates and a contrary policy of relying on the prospect of regulatory lag to ignore lost revenues in the setting of conservation goals. Setting conservation goals on the TRC test *will* result in a greater level of lost revenues, *will* result in a greater likelihood of a rate case (along with the increased uncertainty, increased regulatory costs, and increased workload requirements of a rate case), and *will* result in cross-subsidies between participants and non-participants. These facts cannot be summarily dismissed simply to promote the use of one cost-effectiveness test over another. Contrary to witness Woolf's contentions, it is his dismissal of these outcomes that would be inconsistent with the policies used by Florida to set rates.

III. BILL IMPACTS VERSUS RATE IMPACTS

Q. What do witnesses Mims and Woolf say about the issue of bill impacts versus rate impacts?

A. They both generally take the position that bill impacts (by which they apparently mean the average bill impact for all customers) should be the primary driver in setting conservation goals. As I have previously discussed, they are dismissive of the fact that their recommended TRC test will increase rates and result in cross-subsidies. They attempt to support their position by asserting that FEECA requires the consideration of costs as reflected in participant bills and the dismissal from consideration of the higher rates paid by both participants and non-participants. Witness Woolf goes on to state that FEECA does not even mention the minimization of rates.

Q. Are they correct in their assertions?

A. No, they are wrong. Once again, they choose to ignore statutory language that does not support their position. In addition, they try to narrowly define statutory terms to make them better fit their assertions.

Q. Please explain how they have ignored statutory language.

A. Both witnesses Mims and Woolf choose to ignore Section 366.81, F.S., which clearly uses the terminology of "rate or rate structure" in giving direction to the Commission to set conservation goals in a non-discriminatory way. This statutory provision has been relied upon by the Commission to consider rate impacts in setting goals so as to minimize cross-subsidies between participants and non-participants. As I stated earlier, this practice has been confirmed by the Florida Supreme Court.

Q. Please explain how witnesses Mims and Woolf have narrowly defined statutory language to support their position.

A. They choose to narrowly define the term "cost," as it is used in FEECA, to be devoid of concerns for higher rates, asserting that FEECA is only concerned with bill impacts and not rate impacts. A good example of this narrowly-focused definition of cost is found in witness Woolf's testimony. He references Section 366.82(7), F.S., which uses the terminology "costs passed on to customers." He states that this language shows that FEECA emphasizes costs over rates.

Q. Do you agree with his conclusion?

A. No, I do not. This overly-restrictive definition could rob the Commission of much needed discretion to consider rate impacts consistent with its overarching regulatory responsibilities and is simply not consistent with the general meaning of the phrase "costs passed on to customers." Whenever the phrase "passed onto customers" is used in this context, it generally connotes rate impacts. I do not believe that the Florida Legislature intended the more restrictive definition used by witness Woolf.

Q. Has the Commission had the opportunity to interpret and implement this statutory provision?

A. Yes, at the time the Commission was considering FPL's Modified DSM Plan that was filed to meet the goals established in the last goals setting proceeding, the Commission cited Section 366.82(7), F.S. as giving it the flexibility to modify FPL's Plans and Programs.

Q. What was the nature of the modification made by the Commission pursuant to Section 366.82(7), F.S.?

A. The Commission was concerned that the rate impacts on customers of the plans to meet the goals were too high. The Commission rejected FPL's Modified Plan and decided to continue FPL's then existing plan, specifically citing its concern on rates:

> As we noted above, the Modified Plan filed by FPL is projected to meet the goals we previously established, but at a significant increase in the rates paid by FPL customers. We find that both Plans filed by FPL (Modified and Alternative) will have an undue impact on the costs passed on to consumers, and that the public interest will be served by requiring modifications to FPL's DSM Plan.

The Commission went on to address the solution to its concern over the high rate impacts:

> The rate impacts of the existing Plan are relatively minor. We find that the Programs currently in effect, contained in FPL's existing Plan, are cost effective and accomplish the intent of the statute.

Q. What is the significance of the manner in which the Commission interpreted and implemented this statutory provision?

A. The significance is two-fold. First, the Commission interpreted Section 366.82(7), F.S. to give it the discretion to consider rate impacts when determining "undue impact on the costs passed on to customers." Second, it speaks of rate impacts and the "costs passed on to customers" in the same breath, clearly indicating that the Commission considers an increase in rates to be tantamount to increasing costs for customers. The Commission did not interpret this statutory provision to limit the Commission's discretion and to imply that rates are not relevant when setting conservation goals, as witness Woolf would have it.

Q. Other than this most recent example, has the Commission previously dealt with the definition of the term "cost" to mean bill impacts to the exclusion of rate impacts?

A. Yes, this is not a new issue. Other parties have also tried to impose a narrow definition of "cost" that would preclude consideration of rate impacts and the RIM test. The Commission was faced with this very issue in a motion for reconsideration of Order No. PSC-94-1313-FOF-EG filed by LEAF. In its Order No. PSC-95-0075-FOF-EG, the Commission denied LEAF's motion and reaffirmed its use of the RIM test, stating:

> LEAF's argument that Rule 25-17.001(7), Florida Administrative Code, uses the term "cost" in a fashion that mandates the use of the TRC test to the exclusion of the Participant and RIM tests in setting goals is at odds with the flexibility given under FEECA and preserved in our conservation goals and conservation cost-effectiveness rules. LEAF construes the term "cost" as meaning "bills" when the more plausible contextual interpretation is that "cost" means "rates". There has been no Commission failure to consider bill impact. We have chosen to keep rates lower for all customers, lowering bills for non-participants and participants.

It was this decision that was upheld by the Florida Supreme Court in the case I earlier cited.

Q. What does witness Mims say in regard to this issue?

A. She is dismissive of the use of rates when determining conservation goals. She said it would be illogical to do so because customers care about their bills, not their rates.

Q. Is her assertion correct?

A. No, her position is myopic. I agree that customers are truly concerned about their bills. However, customers are also truly concerned about their rates. To suggest that rates are irrelevant to customers is simply not reality.

Q. Please explain why customers are concerned about their rates.

A. Rates send important pricing information to customers. Because bills are a function of rates and consumption, rates are an important part of the equation. Moreover, the pricing information sent to customers through rates is used to make decisions about consumption. It is the level and structure of rates that are used by customers to make simple decisions such as where to set their thermostats or the preferred time of day to wash their clothes, to more involved decisions such as installing new more efficient air conditioning or expanding a business in an economical manner. Proponents of energy conservation should be the first to recognize that rates send the necessary pricing information to make informed decisions on the merits of pursuing energy efficiency measures.

Q. Are there other ways in which rates are important to customers?

A. Yes. Customers expect and deserve rates that are fair, equitable, and nondiscriminatory. They want to know that the rates they pay are the same as the rates paid by all other similarly situated customers on the system. They also do not expect their rates to be higher because of the actions of others or benefits given to other customers for which they do not qualify. It is this last customer expectation which makes it so important that the rate impacts of participants versus non-participants be recognized. Rates are established in Florida with the goal of protecting the general body of customers. This same standard is equally applicable to both base rates and rates that are passed through to customers through the Energy Conservation Cost Recovery clause.

IV. TWO-YEAR PAYBACK SCREENING CRITERION

Q. Has the Commission consistently used a two-year payback criterion to account for free riders?

A. Yes, the two-year payback criterion was first used by the Commission in the 1994 goals setting proceeding. It was adopted as a means to account for free riders, as required by Rule 25-17.0021, F.A.C. It has been consistently used since 1994, with the exception of the last goal setting proceeding. In that case, the Commission used a modified two-year payback criterion, in which a selected number of measures that were traditionally screened were nevertheless allowed to be recognized for goal setting. This had the impact of setting goals higher than they otherwise would have been set.

Q. Do witnesses Mims and Woolf agree with the use of the two-year payback criterion to account for free riders?

A. No. They do acknowledge that the effect of free riders should be recognized, but they disagree with the two-year payback method of doing so. Witness Mims even describes the two-year payback criterion as "archaic." Instead, they propose the use of a totally different approach based on customer surveys. Such an approach has never been used before in Florida.

Q. Do you agree that a different free rider screen should be used?

A. No. Instead of being "archaic," I believe the two-year payback criterion is more aptly described as "having withstood the test of time" and that it should again be used in this goal-setting proceeding to account for free riders.

Q. Why is that your position?

A. I believe the two year payback criterion should be used for two reasons. First, the intervenor witnesses' suggestion to use customer surveys is untried and unproven in Florida. Further, their suggestions appear more theoretical than substantive. Neither witness has presented any verifiable evidence as to how their customer surveys, which have not yet even been conducted, would be applied in the current goal-setting proceeding. To my knowledge, they have not presented any actual calculations or mechanics to apply their theoretical approach to adequately screen for free riders as contemplated and required by Rule 25-17.0021, F.A.C. And second, their criticisms of the tried and proven two-year payback criterion are unfounded.

Q. What are their criticisms to which you refer?

A. Witness Mims essentially states that the two-year payback criterion is either inaccurate, because it is a blanket approach that uses the same free ridership rate for every measure, or it is incorrect, because it assumes there is a 100% penetration for all measures with a payback of two years or less. Witness Woolf criticizes the two-year payback because he says that it mistakenly assumes that customers know and understand the economic concept of payback periods.

Q. Does the two-year payback criterion assume there is a 100% penetration for all measures with a payback of two years or less?

A. No, it does not. To better explain this, it is necessary to understand what the two-year payback criterion is and what it is designed to do. First, the two-year payback criterion is a tool to be used by the Commission to recognize that there are free riders and to set goals appropriately. It is not and was never intended to be a bright-line, 100% accurate predictor of customer actions and choices under all circumstances. It does correctly assume, for those customers who are willing to consider an energy efficiency measure, that they will make decisions in their own economic interest. The two-year payback criterion further assumes that years to payback is an objective measure, the calculation of which can be verified, to use to differentiate those customers who would make the investment without an incentive and those who would need an additional incentive to make the investment. If customers who would have adopted the measure without an additional incentive nevertheless receive an incentive, they become a free rider and impose additional and unnecessary costs on the general body of customers.

The two-year payback criterion does not, nor should it, assume that 100% of all customers will adopt a measure if its payback is two years or less. It does assume that two years is a reasonable point of differentiation to predict where customers are more likely to adopt a measure, based on its own inherent economic attractiveness, without additional incentives and costs on the general body of customers. In reality, some customers will not adopt a measure regardless of its payback, while others will adopt measures with paybacks greater than two years. Two years has been used as a reasonable point to make that differentiation.

Q. Why should those customers who are motivated by their own economic interests be the focus of the debate?

A. We need to remember that the purpose of this proceeding is to set conservation goals and then subsequently to adopt programs that will incent customers to implement cost-effective conservation measures to achieve those goals. Therefore, it is only those customers who are willing to act in their economic interests by availing themselves of the programs and incentives that should be targeted. For those customers who are not motivated by economics or chose not to participate for other more basic reasons, it is unlikely that offering incentives is going to change their views. As such, it is only those customers who are motivated for economic reasons that should be subject to the free rider screens and have goals set and programs offered for them to act consistent with their economic interests. Stated differently, for those customers who are not motivated by the economics of the offering, no level of goals or incentives are likely to have an impact and have them adopt conservation measures. Therefore, the two-year payback criterion does not assume a 100% penetration for measures with a payback of two years or less and it would be foolish to suggest otherwise.

Q. Can you point to an example of this?

A. Yes, a good example can be found in the testimony of witness Mims. She states that Compact Fluorescent Lights (CFLs) have only an 18% penetration in South Carolina and this is after years of offering additional financial incentives. She concludes there must be non-financial reasons for such a low penetration level. I agree and this begs the question: Would it be reasonable to assume that the 18% CFL penetration could have been achieved, because of the inherent cost-effectiveness of CFLs, without burdening the general body of customers with the costs of the incentives? If the payback on CFLs in South Carolina is two years or less, application of the two-year payback criterion would answer that question in the affirmative.

Q. Is there any other indication that rebates on CFLs may suffer from free rider impacts?

A. Yes. Home Depot, which claims to be the world's largest seller of light bulbs, tracked sales of energy efficient bulbs across the entire country. The Home Depot ranking has the Miami/Ft. Lauderdale/West Palm Beach market and the Orlando market in the top ten nationally in energy efficient bulb consumption per capita. These high rankings were accomplished without utility sponsored incentives and are even more impressive when you consider that FPL's rates are below the national average. This indicates that incentives are not needed to get customers to adopt energy efficient bulbs, presumably due to the bulb's inherent economic attractiveness. It further indicates that when incentives are offered for measures with paybacks of two years or less there could be material free rider impacts. Interestingly, no South Carolina market was even in the top fifty nationally in spite of the incentives that are offered there. The strong implication is that there is a certain portion of the customer population that make decisions on the basis of economic considerations and do not need an incentive to implement measures that have a short payback, while there is another portion that make decisions for non-economic reasons, unaffected by the availability of incentives.

Q. Is witness Mims correct in her assertion that the two-year payback criterion is a blanket approach that applies the same free-ridership rate to every measure?

A. No. The two-year payback criterion is a pass/fail screen, but it is applied to each applicable measure based on the economics of that measure. A review of the Commission's rationale when the two-year payback criterion was first approved illustrates this point. During the initial goal setting proceeding in 1994, two investor-owned utilities proposed a blanket percentage reduction to their goals to account for free riders. The Commission rejected the blanket approach as being arbitrary and unsupported by competent and substantial evidence and further noted that different demand-side measures have different free rider impacts. FPL took a different approach and proposed a two-year payback criterion to screen specific DSM measures. Because it was not a blanket approach, the Commission did not take exception to FPL's proposal to account for free riders and set FPL's goals accordingly.

Q. While criticizing the two-year payback criterion, which she mischaracterizes as being a blanket approach, does witness Mims endorse a blanket approach elsewhere in her testimony?

A. Paradoxically, yes. Her bottom-line recommendation is to set energy efficiency goals for all of Florida's investor-owned utilities at 0.75% of retail sales and ramping up to 1.0% a year later. This is the ultimate blanket approach. Her blanket goal recommendation ignores the unique nature of each utility and the varying cost-effectiveness of the programs for each individual utility system.

Q. Do you agree with witness Woolf's assertion that the two-year payback criterion should be rejected because it mistakenly assumes that customers know and understand paybacks?

A. No, for three reasons. First, the issue is not whether customers know and understand paybacks, the issue is whether the two-year payback criterion is a reasonable tool for the Commission to use to differentiate customers between those that will likely take action on their own and those that may need additional economic incentives to take action. Second, witness Woolf does not give Florida customers the credit they deserve. As I explained earlier, the focus should be on those customers who are willing to have their decisions impacted for economic reasons. These customers are capable of understanding whether an investment should be made, regardless of whether they actually do the math to quantify it in terms of a payback. There is a wealth of information available to those customers who are motivated to act in their own economic interests. For example, manufacturers of certain appliances are required to disclose many of their appliances' energy costs and efficiency information based on Department of Energy test procedures. This information is typically shown on bright yellow "EnergyGuide" labels attached to the appliances. In addition, the Commission has an assortment of information on its website to help customers save energy, including its Conservation House, an interactive graphic which provides informative "point and click" conservation tips for customers. In short, customers who are willing to have their decisions impacted for economic reasons should be able to readily obtain pertinent cost information and should be sophisticated enough to judge for themselves whether it is in their best economic interest to take action. Conversely, following witness Woolf's logic would mean that these same customers would be unsophisticated enough to judge whether a utility offered conservation measure and any incentives that may go along with it are in their best economic interest. If witness Woolf's assertion were true, the fundamental basis for setting conservation goals and offering conservation programs that motivate customers to make cost-effective decisions to conserve energy would disappear! And lastly, even witness Woolf acknowledges that the concept of paybacks has a useful role. Witness Woolf states:

> As explained in DEF and FPL's testimony, the number of payback years influence consumer decisions for adopting energy efficiency measures, and customer payback should influence customers'

decisions whether to purchase solar PV and Solar Hot Water (SHW) systems. Thus, if the Utilities were to provide some kind of financial support such as rebates or low-interest loans to their customers, such support should increase the number of customers adopting solar systems.

Q. Do the intervenor witnesses offer a workable alternative to the two-year payback criterion?

A. No, they only offer vague references to customer surveys and assert without support that the surveys would be more accurate. They offer no workable alternative with the requisite program-specific evaluations and quantifications necessary to set goals as required by FEECA and Rule 25-17.0021, F.A.C.

V. INCLUDING "NON-ENERGY BENEFITS" IN DETERMINING COST-EFFECTIVENESS

Q. What are "non-energy benefits"?

A. Both witness Mims and witness Woolf introduce the terminology "non-energy benefits." Witness Mims describes non-energy benefits as the benefits that are not currently captured by the avoided cost or the energy efficiency savings. The concept seeks to increase the quantification of benefits in the TRC test so that more programs would be found to be cost-effective.

Q. Is this concept a new one?

A. The terminology may be new, but the concept is not. The same concept can be or has been generally described as "externalities," "non-quantifiable benefits," and "non-jurisdictional benefits." Regardless of the terminology, the concept seeks to add benefits that are external to the traditional bounds of ratemaking and beyond the way Florida has interpreted its regulatory jurisdiction. As a general rule, these external benefits are difficult to quantify and their quantification requires the liberal use of assumptions and often the use of blanket adjustment factors.

Q. Has the Commission previously addressed this concept in the context of setting conservation goals?

A. Yes, the concept was raised by several intervenors in the 1994 goal setting proceeding. In rejecting use of the concept, the Commission noted that the benefits were either non-quantifiable or else were not quantified in the record. The Commission further observed that adding these external benefits to the TRC test would essentially convert it to a societal test.

Q. Does witness Mims give examples of the non-energy benefits she believes should be added to the TRC test in this proceeding?

A. Yes, the examples she gives are: (1) improved health and safety; (2) increased comfort and aesthetics; and (3) reduced maintenance costs for participants. All of these perceived benefits are external to the traditional ratemaking and jurisdictional bounds. She offers a fourth example that could be considered as an internal benefit: reduced customer arrearages and reduced bad debt write-offs.

Q. Are the non-energy benefits she cites appropriate for determining cost-effectiveness?

A. No. The first three benefits are either non-quantifiable or difficult to quantify and are beyond the traditional bounds of ratemaking. The last perceived benefit is theoretical and could actually be a cost instead of a benefit under the TRC test. This is because the TRC test is unconcerned with rate impacts and is unconcerned with cross-subsidies between participants and non-participants. As such, non-participants would see higher rates and the possibility of increased arrearages and write-offs. These might or might not be offset by reduced arrearages for participants. Like all of the other example benefits, this too would be difficult to quantify.

Q. Does witness Mims or witness Woolf attempt to quantify their non-energy benefits?

A. Not really. They do not identify and quantify their perceived non-energy benefits with any level of specificity. Witness Woolf recommends blanket adders ranging from 10% to 50%, but offers no quantification or justification for those adders. Witness Mims references various states that have considered non-energy benefits, but offers no explanation of how those states' decisions would or could apply in Florida.

Q. Witness Mims' first example is improved health and safety. Should this benefit be included in determining cost-effectiveness because it is a worthwhile societal benefit?

A. No. The issue in determining cost-effectiveness is not whether the benefits are worthwhile from a societal perspective. Rather, the issue is whether the costs of obtaining the benefits have been internalized. For example, regulations to improve health by reducing mercury emissions have been internalized. If conservation measures can avoid or defer the need for a new generating plant and its internalized cost of complying with mercury emission regulations, those benefits should be recognized – and they are, consistent with established Commission practice and Rule 25-17.0021 F.A.C. The same is true for safety, as long as the costs of complying with OSHA regulations and applicable electrical safety codes have been internalized.

Q. Could adopting the use of non-energy benefits in setting conservation goals have other, perhaps unintended, consequences?

A. Yes, doing so would put the Commission on the edge of the proverbial "slippery slope."

Q. Please explain.

A. First, the Commission would have to identify the perceived benefits and then attempt to quantify them. Given that the benefits are often nebulous and non-internalized, they would be open to much subjective reasoning. Depending on the results of the exercise of such subjective decision making, the impacts on customer rates could be substantial. Second, including non-internalized costs and benefits in the setting of conservation goals would be inconsistent with the way the Commission sets rates for supply-side options. Consistent with sound regulatory principles, Florida has a long history of setting rates on the actual cost of providing service, based on determinations of reasonableness and prudency of those costs. By definition, this includes only internalized costs and not the costs associated with achieving some theoretical benefit. Therefore, there would be a disruptive inconsistency between demand-side and supply-side options. It could also mean that costs and rates to consumers would be higher. The issue succinctly stated would be: Is it appropriate to have all customers pay higher rates to choose an option that does not add to the quality of service provided, but does provide some nebulous benefit such as aesthetics beyond what is already required by local zoning ordinances or other applicable standards of construction? My answer is no.

VI. INTERVENORS' PROPOSED DSM GOALS

Q. What DSM goals do witnesses Mims and Woolf recommend to the Commission?

A. Both witness Mims and witness Woolf recommend blanket goals expressed as a percentages of utility retail sales. Witness Mims recommendation is 0.75% increasing to 1.0%. Witness Woolf recommends 1.0% by 2019, along with capacity savings based on a ratio of recent experience and use of his 1.0% energy goal.

Q. Would this blanket approach be appropriate?

A. No. Their proposed goals are not consistent with the requirements of FEECA and Commission rules. Mr. Woolf spends much time and dozens of pages trying to argue that the Utilities' proposed goals do not comply with FEECA, only then to offer a proposal that is completely disconnected from any of the FEECA requirements. Indeed, the basis of his proposed goals is that, to paraphrase, "other states are doing this, so should Florida" – making clear that FEECA and this Commission's applicable rules are of little concern to him. He states that his proposed goals are based on "extensive knowledge of DSM opportunities, achievements, and plans in other states." Likewise, witness Mims' recommended blanket percentage goal is significantly based on her reasoning that five other states have been able to achieve her recommended level of savings and that Florida should be able to do the same. She specifically references the five "leading" states in The 2011 State Energy Efficiency Scorecard.

Q. How would their recommended goals be inconsistent with FEECA and Commission rules?

A. To name just a few inconsistencies, their goals do not:

- Rely on a cost-effectiveness test.
- Address system reliability.
- Place demand-side and supply-side resources on a level playing field.
- Keep rates low and minimize cross-subsidies.
- Address free riders.

Q. Is it appropriate to make comparisons between Florida's DSM goals and those in other states?

A. It is not unusual to make state comparisons and such comparisons can sometimes provide information to aid in making regulatory policy decisions. However, just as when making comparisons between regulated utility companies, there are important limitations and considerations which should be made before drawing conclusions from such comparisons. First, it is imperative to recognize that there can be inherent and sometimes significant differences in the costs and rates for providing service. These differences could be due to numerous factors such as size, age of the system, customer mix and density, geographical and climate differences, fuel mix, and access to fuel sources, to name just a few. Therefore, such comparisons can be used to identify areas that could call for more investigation and scrutiny, but rarely if ever should comparisons be used to draw a conclusion on their face. In making state comparisons, it is also imperative to recognize that each state has its own body of enabling statutes which sets forth their respective jurisdictions and establish a framework, and sometimes explicit direction, in making policy decisions. Each state regulatory agency is then expected to make decisions consistent with its specific statutory framework and Florida is certainly no exception.

Q. Have witnesses Mims and Woolf used state comparisons in an appropriate manner?

A. No, they both have essentially concluded because other "leading" states are doing certain things that Florida should do the same. They make overly generalized assumptions and ignore substantive differences that may exist between Florida and their so called "leading" states. Witness Woolf even makes the overly generalized assumption and strikingly offensive implication that Florida does not recognize what is good for its customers: "...one of the biggest differences between Florida's regulatory environment and those of other states is that many regulators and other stakeholders, especially those in the leading states, recognize that well-designed, cost-effective DSM is good for customers."

Q. What are the areas where there may be substantive differences between Florida and the intervenor witnesses' "leading" states?

A. Such a comprehensive analysis is well beyond the scope of my rebuttal testimony. However, two areas come to mind: rate (and presumably cost) level differences; and differences in statutory framework and guidance.

Q. Why are differences in rate levels important?

A. First, setting conservation goals without regard to rate impacts could put upward pressure on rates. Second, and perhaps more importantly, higher rates can show that a higher level of conservation may be warranted. As a general proposition, the higher the costs that are being avoided by conservation, the higher the amount of conservation that is cost-effective. Therefore, if a state has higher rates, it may be appropriate for them to have higher conservation goals. That may be good policy for that state, but it cannot be automatically inferred that it is good policy for

Florida.

Q. What are the rate levels in the intervenor witnesses' "leading" states?

A. My Exhibit JTD-3 shows that most of the "leading" states have electric rates higher than the national average, and much higher than Florida in general and FPL in particular. Given that their rates are higher, a higher amount of DSM may be appropriate for them. It may also be true that their desire to set higher goals, without primary reliance on the RIM test, is contributing to their higher rates. Regardless, what is clear is that the "leading" states' conservation goals cannot be assumed to be appropriate for Florida, nor should Florida seek to emulate their electric rates.

Q. Witnesses Mims and Woolf repeatedly state that Florida and Virginia are the only states that use the RIM test, implying that Florida is not conforming to accepted practice. Should this be a basis to conclude that the RIM test is inappropriate for Florida?

A. No. Once again the intervenor witnesses draw inappropriate inferences to conclude that Florida should rely exclusively on the TRC test. Further, many other states continue to use the RIM test in conjunction with the TRC test. And other states impose rate impact limitations on the amount of conservation they approve for their regulated utilities. This, to an extent, is relying on the RIM test to set conservation goals. And most importantly, Florida's historical reliance on the RIM test has proven both appropriate and beneficial for Florida customers.

Q. Has Florida's historical reliance on the RIM test been proven to be appropriate and beneficial?

A. Yes. Florida's historical reliance on the RIM test has resulted in a significant amount of conservation achievements. This is shown by the following excerpt from the Commission's February 2014 Annual Report on FEECA:

> Over the last thirty-three years, the FEECA utilities' DSM programs in total have reduced winter peak demand by an estimated 6,465 megawatts (MW) and summer peak demand by an estimated 6,737 MW. The demand savings from these programs have resulted in the deferral or avoidance of a substantial fleet of baseload, intermediate, and peaking power plants. These programs have also reduced total electric energy consumption by an estimated 8,937 gigawatt-hours (GWh).

These accomplishments were achieved by devoting substantial resources ($5.7 billion since 1981) in a cost-effective manner that has helped maintain reliability *and* minimize rate impacts. As my Exhibit JTD-3 shows, Florida's rates are below the national average, even though Florida has unique challenges presented by its geographical location, its climate, its customer mix, and its lack of indigenous fuel sources.

Q. Why did you include Virginia on your Exhibit JTD-3?

A. Witness Mims states that Virginia is the only other state that primarily uses the RIM test. I included Virginia to compare its rates with those of the so called "leading" states. As my exhibit shows, Virginia has rates well below the national average. Perhaps a coincidence, but certainly a fact that should caution against departing from the RIM test here in Florida.

Q. Why is it important to consider potential differences in statutory framework before making inferences about the appropriateness of conservation goals?

A. Each state must follow its specific statutory framework. To automatically infer that the goals established in another state under a different statutory framework are what's best for Florida, is at best flawed and at worst a potentially ill-advised way to circumvent Florida's statutes and rules.

Q. Do you have any examples of how the intervenor witnesses' "leading" states have different statutory frameworks?

A. Yes, I do. But let me be clear, I have not done an exhaustive analysis of all the differences that may exist. The following examples are sufficient to make the point that using these states to infer goals for Florida would be inappropriate:

- In June 2006, the Hawaii State Legislature enacted legislation to create a public benefits fund (PBF) for energy efficiency and demand side management. The PBF is funded by a surcharge on utility bills that is based on a percentage of total utility revenue. For 2011 and 2012, the PBF has a target budget of 1.5% of total projected revenue. From 2013 onwards, the PBF will have a projected target budget of 2% of total projected revenue.
- In Minnesota, each utility is required to spend 1.5% of its gross operating revenue (2.0% if it has nuclear generation) on energy conservation. Each utility is also required to have an annual energy-savings goal equivalent to 1.5% of gross annual retail energy sales.
- In Nevada, the TRC test is mandated.
- A cursory review of Rhode Island's statutes did not reveal any unique prescriptive measures. However, Rhode Island's Energy Efficiency & Resource Management Council reported that in 2013 1.5 billion kWh were saved at a cost of $0.43 per kWh saved. I

note that this is substantially higher than the $0.02 to $0.04 levelized cost of electricity value often projected for DSM as discussed by Dr. Sim.

- In Vermont, cost-effectiveness is required to be measured using three tests: (1) TRC; (2) the Utility Cost test; and (3) the Vermont Societal Cost Benefit Test. The RIM test is not included.
- It should be noted that all of these states have relatively aggressive Renewable Portfolio Standard (RPS) requirements.

Q. How do these requirements and outcomes compare to Florida?

A. At the risk of stating the obvious, the Florida Legislature as seen fit to not impose a public benefits charge, to not mandate a specified level of spending on conservation, to not require goals based on a specified level of sales, to not require a specified cost-effectiveness test, to not require the consideration of societal benefits, to not impose an RPS requirement. What the Florida Legislature has done is require that conservation goals be cost-effective, require that the cost to the general body of customers be considered, and require that impacts on non-participants and cross-subsidies be considered. And the Commission, by rule, has set forth the basis on which goals will be set and that free riders must be considered.

VII. GOALS FOR DEMAND-SIDE RENEWABLE ENERGY SYSTEMS

Q. What did the Commission decide in the last goals setting proceeding in regard to demand-side renewable energy systems?

A. Despite finding that none of the demand-side renewable energy systems were cost-effective, the Commission nonetheless directed the investor-owned utilities to file pilot programs encouraging solar water heating and solar photovoltaic (PV) technologies.

Q. Were demand-side renewable energy systems a new consideration within the last goal setting proceeding?

A. Yes. A definition of demand-side renewable energy systems and a requirement to consider them were added to Section 366.82, F.S., as part of the 2008 revisions to FEECA which I earlier described.

Q. Did the 2008 revisions make any changes or otherwise alter the existing standards and requirements in Chapter 366, F.S.?

A. No. Other than further clarifying that impacts on the general body of customers must be considered, the revisions did not change the requirements that programs and initiatives, including demand-side renewable energy systems, must be cost-effective. Likewise, there were no changes to the requirement in Section 366.81, F.S., that rate impacts should be nondiscriminatory.

Q. Do the pilot programs continue to be non-cost-effective?

A. Yes, as more fully described in the testimonies of Dr. Sim and Mr. Koch, the pilot programs continue to be non-cost-effective under both the TRC test and the RIM test. As a result, FPL is proposing a goal level of zero for demand-side renewable energy systems. FPL further concludes that resources would be better directed at research and development (R&D) to gather information on the system impacts of both DSM and non-DSM PV applications.

Q. Is FPL's proposal to set the goal for demand-side renewable energy systems at zero permissible and appropriate under FEECA?

A. It is not only permissible, but is preferred when the programs are not cost-effective. A goal level of zero would best protect the general body of customers and minimize cross-subsidies between participants and non-participants.

Q. Has the Commission previously set goal levels of zero?

A. Yes. As part of the 1999 and 2004 goals setting proceedings, the Commission set goals at zero for both JEA and the Orlando Utilities Commission. A good example of the Commission's rationale is found in Order No. PSC-00-0588-FOF-EG:

> In conclusion, because no DSM measures were found cost-effective for JEA, it is not appropriate to establish conservation goals for JEA. Accordingly, we find that JEA's proposed annual residential winter and summer kW and annual residential kWh conservation goals of zero for the period 2001 through 2010 are appropriate. Likewise, we find that JEA's proposed annual commercial/industrial winter and summer kW and annual commercial/industrial kWh conservation goals of zero for the period 2001 through 2010 are appropriate.

Q. Despite setting goals at zero, did the Commission nonetheless allow JEA to determine whether it should continue to offer some DSM programs?

A. Yes. The Commission noted that JEA is not a rate-regulated utility and does not recover the costs of DSM programs through the Commission's ECCR proceedings.

Q. Would it likewise be appropriate for FPL to continue its pilot programs even if the goal for demand-side renewable energy systems were set at zero?

A. No. As a rate-regulated utility, the costs of the pilot programs are almost immediately passed through the ECCR. This means that the general body of customers has and would continue to have higher rates with the pilot programs. And just as important, there would be continued cross-subsidies between participants and non-participants.

Q. Is the fact that the Commission approved solar pilot programs in the last goals setting proceeding a valid reason to continue them as part of the current goal setting proceeding?

A. No. The pilot programs were initially approved based on an assumption that the then new statutory revisions somehow required them. Furthermore, the Commission approved them with the possibility that unique cost-saving opportunities could be captured as part of the initial pilots. Even assuming that the 2008 statutory revisions somehow required the Commission to make an initial effort to promote non-cost-effective renewables, the pilots have been in existence long enough for the Commission to make the judgment that they remain non-cost-effective and are likely to remain so. It is the purpose of the five-year reviews in FEECA to make these appropriate informed decisions based on sound economics, to discontinue non-cost-effective programs, and explore new cost-effective programs consistent with FEECA. The 2008 revisions do not change this most basic tenet of FEECA. FPL's proposal to discontinue the current pilots, to set goals at zero, and to engage in further R&D is consistent with this basic tenet of FEECA.

This R&D will help to gather information on the system impacts of both DSM and non-DSM PV applications.

Q. If the Commission desires to exercise its discretion to pursue greater solar generation in Florida, how should the Commission proceed?

A. Solar generation that is cost-effective relative to other available resource alternatives can and should be pursued straightforwardly under Florida's existing energy policy and regulatory framework. If in exercising its discretion to regulate in the public interest the Commission decides that solar generation should be more aggressively pursued, I would encourage it to do so in a way that continues to take into account the relative cost-effectiveness of solar generation alternatives and seeks to minimize cross-subsidies among customer groups. Specifically, I would recommend that the Commission focus on those alternatives that are most economic relative to the range of available solar alternatives and that do not increase subsidies between participants and non-participants. A good example would be central station solar generation. Due to greater construction and operational efficiencies compared to demand-side and distributed solar generation, central station solar would be cost-effective relative to those solar alternatives and perhaps even moderately cost-effective relative to all other resource alternatives. Furthermore, because central station solar generation would be utility owned and operated for the benefit of all customers, it would not create subsidies between participants and non-participants.

VIII. CONCLUSION

Q. What is your conclusion?

A. The goals proposed by witnesses Mims and Woolf are blanket goals based on inappropriate inferences from other states. Furthermore, their goals do not meet the requirements of FEECA and Commission rules. The intervenor witnesses' goals should be rejected. Instead, goals should be set based on the use of the RIM test, which benefits the general body of customers and minimizes cross-subsidies. The Commission should also continue to use the two-year payback criterion to account for free riders.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. DONALDSON:

Q Would you have a summary for your -- the Commission of your rebuttal testimony?

A Yes.

Q Please provide that at this time.

A Yes. Good morning, Commissioners. My rebuttal testimony, in that testimony I respond to many of the positions and recommendations contained in the testimony of SACE's witness Mims and the testimony of Sierra Club witness Woolf. Both of these witnesses liberally criticize a number of precedents and policies that have been traditionally and successfully used in Florida to comply with the requirements of FEECA.

They also criticize rules of this Commission and decisions of this Commission that have been upheld by the Florida Supreme Court. Their criticisms are unfounded and their recommendations are inappropriate, unnecessary, contrary to ***Florida Statutes*** and rules, and not adequately sustained by the evidence presented. In essence, their mission is to pressure the Commission into embarking on an unprecedented path that would inappropriately and arbitrarily increase DSM goals.

To achieve their mission, these witnesses would have the Commission reject the long-term policy of using the RIM test and to ill-advisedly embrace the TRC test to the exclusion of the RIM test. However, as evidenced in the 2009 goal setting proceeding, doing so could result in large rate increases to customers and increased subsidies between participants and non-participants.

The Intervenor witnesses would also have the Commission ignore these cross-subsidies as being moot or irrelevant. However, doing so would be inconsistent with the Commission policy and ***Florida Statutes*** and, once again, decisions of the Florida Supreme Court.

The Intervenor witnesses would have the Commission ignore rate impacts on their implausible premise that customers are not concerned with rates. They also ignore statutory provisions which specifically require the Commission to consider rate impacts.

The Intervenor witnesses would have the Commission either ignore free riders or else use an unsubstantiated and untried means of accounting for them. Ignoring free riders would be inconsistent with Commission rule, and the Commission has a long-held policy of using a two-year payback criterion to conservatively account for free riders.

The Intervenor witnesses would have the Commission inappropriately inflate goals by using external or non-energy costs and benefits to justify forcing customers to pay more for those goals.

Doing so would be contrary to Commission policy, establish rate making in Florida, and would result in unnecessarily higher rates for customers.

And, finally, the Intervenor witnesses would have the Commission adopt goals based upon their overarching and misapplied contention that other states' DSM levels should be applied in Florida. This approach ignores statutory requirements and factors unique to Florida and the inappropriate inferences from other states. Their proposed goals do not meet the requirements of FEECA or Commission rules; they should be rejected.

Instead, goals should be based upon the use of the RIM test, which -- excuse me -- which benefits the general body of customers and minimizes cross-subsidies. The Commission should also continue to use the two-year payback criterion to properly reduce the risk of customers having to pay unnecessarily high incentives to free riders.

This concludes my summary.

MR. DONALDSON: Thank you, Mr. Deason.

FPL turns over this witness for cross-examination.

CHAIRMAN GRAHAM: Thank you.

OPC.

MR. SAYLER: Mr. Chairman, no questions.

CHAIRMAN GRAHAM: Department of Agriculture.

MR. HALL: No questions.

CHAIRMAN GRAHAM: NAACP.

MR. DREW: No questions.

CHAIRMAN GRAHAM: FIPUG.

MR. MOYLE: I have a few.

CHAIRMAN GRAHAM: Sure.

EXAMINATION

BY MR. MOYLE:

Q Good morning, Mr. Deason.

A Good morning.

Q You've been monitoring this proceeding since you last took the stand; correct?

A Yes. Not continuously but off and on.

Q Okay. Have you heard anything from any -- you were here this morning. Have you heard anything from any of the witnesses for the environmental, environmental groups that has caused you to rethink or change the testimony that you gave in direct?

A No, not for me to rethink or change anything in my direct testimony. There was a comment made by Witness Mims yesterday which appeared to me to be a change in her testimony, which perhaps would have changed some of my rebuttal testimony had I known that was her position.

Q Okay. But your testimony that you filed on direct and in all the questions -- I asked you a bunch of questions -- all of that is still good, solid evidence as far as you're concerned as we sit here today?

A Yes.

Q Okay. A couple of things I want to refer you to. On page 10 of your rebuttal testimony, line 16, and you're asked a question about Witness, Witnesses Mims' and Woolf's attempt to marginalize concerns over cross-subsidies. Do you see that?

A Yes.

Q And you state, in part, that I guess you interpreted their testimony to imply that it's okay to promote cross-subsidies when setting conservation goals?

A That's the way I read the testimony, yes.

Q Okay. And I asked witnesses for both, both -- I think I asked both those witnesses whether they supported, their organization supported cross-subsidies, and I think they expressly answered no. Would that cause you to rethink this in any way?

A No. They state in their testimony that they're not promoting cross-subsidies. But when you read in greater detail in their testimony, they talk about things such as the fact that it's their opinion that cross-subsidies are inherent in regulation, they cannot be avoided, and I think Witness Mims even indicated that cross-subsidies are irrelevant because if there's enough people that are subscribing to these programs, that, and the goals are met, that that means that there would be little cross-subsidization. And, of course, I disagree with that.

Q Okay. Let me refer you to Page 12, lines 1 and 2. It's actually a segment of some testimony that starts on the preceding page, but --

A Okay.

Q Are you there?

A I am.

Q The segment I'm referring to, you say -- and, again, there's some previous words -- but, "It is the goal of regulation to prevent cross-subsidies whenever possible, and the Florida Commission makes every reasonable effort to do so." Is that, is that your understanding of the historic policy of the Commission?

A Yes.

MS. TAUBER: Mr. Chairman, I would at this point just lodge an objection against friendly cross.

CHAIRMAN GRAHAM: I agree with you. Move on

Mr. Moyle.

BY MR. MOYLE:

Q The-- if the goal is to prevent cross-subsidies, and you talk about the payback screen, you would agree that the two-year payback screen and the RIM test does that more so than the TRC test; correct?

A Yes.

Q And wouldn't the three -- wouldn't using a three-year payback screen achieve that goal even more so?

A No, I'm not at that point. I believe the two-year screen is adequate. It has been proven to be so. And as I stated earlier, it's not my recommendation to change to a three-year screen.

Q The -- on page 17, lines 19 through 20, you cite a Commission order, as I understand it; is that right?

A Yes.

Q Isn't that a segment? And the Commission in its previous order said, quote, we have chosen to keep rates lower for all customers, lowering bills for non-participants and participants.

Isn't it, isn't it true, if that's the objective and that is a goal, that this Commission is confronted with a choice between a position presented by some of the Intervenors and the position presented by the utilities, and that the utility position, particularly using a three-year screen, would keep rates lower for all customers, lowering bills for non-participants and participants?

MS. TAUBER: Mr. Chairman, same objection, friendly cross.

CHAIRMAN GRAHAM: I'll overrule you. He's -- I see him focusing more on the two- to three-year focus, which is contrary to where this witness's position is.

THE WITNESS: Mr. Moyle, could you repeat the question, please?

BY MR. MOYLE:

Q Sure. I'll just -- I just wanted to refer you to the statement that you have in your testimony about a prior Commission saying we want to keep the rates low for all customers, lowering bills for non-participants and participants. And my question is if the Commission, if this Commission says we agree with that approach, they're presented with some choices in this case. And the -- what's presented by the utilities is more consistent with achieving that goal than what's presented by the intervening witnesses; correct?

A I generally agree, yes.

Q Okay. And if you used a three-year screen, that would result in lower bills for non-participants and participants as compared to a two-year screen.

A No. I can't necessarily agree with that. I think that it could result in being a larger -- more programs or more measures, rather, being screened out than is necessary. And if that were to happen, well, then I'm not sure that you could continue to state that the goals were set at the proper level and that the, and that there would be lower bills for participants and non-participants.

Q Were you here when Mr. Bryant testified on behalf of TECO?

A No, I was not here.

Q Okay. Well, I'll represent to you -- the record will be clear -- I'll represent to you that on their screening analysis they had a document, and it's introduced into evidence, I think, as 185, that showed additional savings to, to ratepayers if you used a three-year screen as compared to a two-year screen. I take it you're not familiar with that analysis or haven't done that analysis?

A I have not done that analysis. That's correct.

Q Okay. But you wouldn't disagree with it.

A I have no basis to disagree with that. It's just a question as to whether one believes that the appropriate tool to effectively and appropriately screen for free riders is two years or three years. And if, if it is believed the better tool is three years, well, then the TECO analysis may be correct. I'm not at that point though.

Q I understand. But you also are agreeing that a two-year screen is the minimum you would recommend.

MS. TAUBER: Objection. Friendly cross.

CHAIRMAN GRAHAM: Actually I think it's been asked and answered.

MR. MOYLE: Well, let me come at it another way, if I can.

CHAIRMAN GRAHAM: Okay.

BY MR. MOYLE:

Q We have differing positions on the appropriate screen. You're saying a two-year screen; FIPUG is saying three or more. What, what do -- if you have indicated that you think two years is a minimum screen to use, that suggests that you may have a view about a maximum screen to use, and I wanted to know what you thought that might be.

A No, I do not have an opinion upon the maximum. I do know that in this case there was staff doing their due diligence wanted information concerning the impacts of a one-year screen and the impacts of a three-year screen. And I did cause to be filed an exhibit where analyses were done to show the internal rates of return even at a three-year screen which showed there to be significant rates of return, which would indicate that there certainly should not be a change from two-year to one-year. But I was still not at the point that we should change from two to three. But certainly it should not been less than two.

Q And that -- you're referencing your Exhibit Number 2 to your direct testimony in that answer?

A Yes.

MR. MOYLE: Okay. Thank you, Mr. Chairman. That's all I have.

CHAIRMAN GRAHAM: Thank you, sir.

Sierra Club.

MS. CSANK: No questions, Mr. Chairman.

CHAIRMAN GRAHAM: SACE.

MS. TAUBER: No questions, Mr. Chairman.

CHAIRMAN GRAHAM: EDF.

MR. FINNIGAN: No questions, Your Honor.

CHAIRMAN GRAHAM: Staff.

MR. MURPHY: No questions.

CHAIRMAN GRAHAM: Commissioners. Commissioner Balbis.

COMMISSIONER BALBIS: Thank you, Mr. Chairman. Thank you again, Mr. Deason, for coming here.

I want to explore a little bit the concept of free riders a little bit more. And I had discussions with a previous witness on the concept of would versus should, and you have a lot of testimony in your rebuttal testimony that addresses the reasons why customers do participate and do not. But aren't there some customers that although they should be participating or installing these conservation measures because there's such a short payback period, isn't it possible that they're not doing it because they can't afford the upfront price or for some other reasons, and, therefore, if the programs are eliminated, they would not be doing so?

THE WITNESS: Yes, I agree, Commissioner. That's very possible. And I think it's probably more likely the low income customers. And, in fact, I even reference a decision by the Commission, an order where I mention the fact that the RIM test is the best test to protect low income customers. But I also have been in attendance at this hearing long enough to understand that there's concerns that perhaps there are, are measures or things that could be done to better address the low income community. I think that message has been sent loud and clear.

I would, I would suggest that during the program, not the, not the goal setting and looking at measures, but when you actually get to the phase of this proceeding to establish programs, that that would be the best time to design programs which are better able to reach that community of customers that perhaps are low income and perhaps are not availing themselves of measures which are cost-effective for them to implement.

COMMISSIONER BALBIS: And I agree. I mean, the situation we're facing now is that the goals have been set or are being proposed that are looking at the cost-effectiveness of programs. And my concern is that if the goals do not reflect programs that pass the RIM test and even if the TRC test is used, pass that as well, the Participants test passed the RIM test but then it's screened out by the two-year payback, those are cost-effective programs that all the body of ratepayers would benefit from. So now we're kicking those out or not setting the goals to account for that and then we're missing a segment of customers that are not going to be able to take advantage of those.

So wouldn't it be better to have the goals reflect that in the program development phase some of these measures will be implemented and shouldn't the goals reflect that?

THE WITNESS: Commissioner, I understand the concern and it is a dilemma. But, no, I would not deviate from the established policy of setting the goals at the right level, which under RIM protects all customers from increased rates. We know that increased rates affect the low income community more than others. So I would certainly maintain the RIM test, and I would continue to, to use the two-year screen because effectively what that does is that it prevents paying incentives to customers who would do the measure anyway. So it just increases costs when you're not getting the efficiencies that you want. So it is, the two-year screen is an efficient way to, to implement DSM.

I think that setting goals at the -- using RIM and using the two-year payback screen, that there's still enough DSM to be accomplished that there is latitude within designing the programs to reach out to the, to the low income community to devise programs that better meet their needs and perhaps address the concerns that they're not, they don't have the means to avail themselves of some of these lower, lower cost, high payback measures.

COMMISSIONER BALBIS: And I agree. It's just, I guess, the main concern that I have is that in the goal development phase you're throwing those programs out essentially because they don't pass the two-year screen, and then now you've indicated that you've heard the message loud and clear that a lot of these low income programs, which were thrown out in the program development phase, may be implemented. So why not just have the goals reflect those programs?

THE WITNESS: Because I think that it would not be the correct thing to do to do away with a well-established policy that actually protects low income customers when it comes to their rate levels that they pay.

As far as the goals level in this case and how to design programs to meet that, those, the needs of that customer group, I would probably need to defer to Mr. Koch, who is, it's more his expertise, and not only in this phase of goal setting but also in program implementation or design and implementation. I've had conversations with him, and he's also heard the message from the Commissioners that this is an aspect that needs to be addressed. And I think that maybe he could shed more light on that for you.

COMMISSIONER BALBIS: Okay. And then -- excuse me -- now focusing on the ones that would have participated or installed a device, et cetera, do you have any information or any way to estimate the should?

Do you understand?

THE WITNESS: No, I have, I have not conducted any study. I don't know of any utilities that have conducted any studies at this phase. I know when they design programs, they look at adoption rates and that sort of thing. The, the two-year payback screen, it is a tool. I think it's, it's a good tool. But, I mean, we've had discussions here as to whether it should be one year, three years, and one can use judgment.

We do know that free riders are a phenomenon that happens. By rule that needs to be addressed. And until there is better evidence that somehow the two-year screen is not the adequate tool at least for purposes of this proceeding, I think there's nothing in this proceeding, no evidence in this proceeding that supports something better than the two-year payback screen. I'm not saying that that tool cannot be refined and used in a better way, and maybe it should be changed or modified to some degree, but I just don't think we have any evidence in this case. And I'm a strong believer that if you have a policy, certainly you can always change your policy, Commissioners. You have that discretion. But I think there should be a strong reason for changing the policy. And we know that regulation, like everything in life, there's changes and there's evolutions. And so at some point maybe the two-year screen should be discontinued or somehow modified. I just don't think we're there yet. We certainly don't have the evidence in this case to make that change.

COMMISSIONER BALBIS: Okay. I just want to point out, I'm not condoning that those that would be doing it anyway who are true free riders, that those should be included. But I'm still struggling with how to address both issues. But thank you for clarifying.

THE WITNESS: Okay.

CHAIRMAN GRAHAM: Other Commissioners?

Redirect.

MR. DONALDSON: None.

CHAIRMAN GRAHAM: Okay. Exhibits.

MR. DONALDSON: Yes. FPL would like to enter into evidence Exhibit Number 150.

CHAIRMAN GRAHAM: We will enter Exhibit 150 into the record.

(Exhibit 150 admitted into the record.)

I think we're done with Mr. Deason. Mr. Deason, thank you very much.

THE WITNESS: Thank you.

MR. DONALDSON: Thank you.

(Transcript continues in Volume 6.)

STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, LINDA BOLES, CRR, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 8th day of August, 2014.

Linda Boles

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