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January 28, 2002

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COMMISSION CLERK

- VIA HAND DELIVERY –

Ms. Blanca S. Bayó
Director of the Commission Clerk and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Re: Docket No. 001148-EI

Dear Mr. Bayó:

I am enclosing for filing in the above docket the original and fifteen (15) copies of the prefiled testimony and exhibits for the following Florida Power & Light Company ("FPL") witnesses:

	Mark R. Bell · 01061-02		K. Michael Davis	01067-02
	M. Dewhurst – 01062-02		Paul J. Evanson	01068-02
	William W. Hamilton	01063	Steven P. Harris	01069-02
01064	Dr. J. Stuart McMenamin		Rosemary Morley	01070-02
	Armando J. Olivera	01065	James K. Peterson	01071-02
	John M. Shearman	01066	Samuel S. Waters	01072-02

FPL is filing these witnesses' testimonies today in accordance with Order No. PSC-02-0089-PCO-EI, dated January 15, 2002. FPL's witnesses sponsor and explain the MFRs FPL has previously filed in this docket. Together with the MFRs, their testimonies demonstrate that FPL's 2002 test year results do not support any reduction in FPL's base rates.

AUS ___
CAF ___
CMP ___
COM Stary
CTR ___
ECR ___
GCL 1
OPC 1
MMS ___
SEC 1
OTH ___

Sincerely,

John T. Butler, P. A.

Enclosures
cc: Counsel of record (w/copy of enclosures)

RECEIVED & FILED

FPSC-BUREAU OF RECORDS

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that true and correct copies of the prefiled testimony and exhibits of Mark R. Bell, K. Michael Davis, M. Dewhurst, Paul J. Evanson, William W. Hamilton, Steven P. Harris, Dr. J. Stuart McMenamin, Rosemary Morley, Armando J. Olivera, James K. Peterson, John M. Shearman and Samuel S. Waters were served by hand delivery (*) or overnight delivery this 28th day of January, 2002 to the following:

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By: ______________________
John T. Butler, P. A.

BEFORE THE FLORIDA
PUBLIC SERVICE COMMISSION

DOCKET NO. 001148-EI
FLORIDA POWER & LIGHT COMPANY

JANUARY 28, 2002

IN RE: REVIEW OF THE RETAIL RATES
OF FLORIDA POWER & LIGHT COMPANY

TESTIMONY & EXHIBITS OF:
SAMUEL S. WATERS

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF SAMUEL S. WATERS

DOCKET NO. 001148-EI

JANUARY 28, 2002

Q. Please state your name and business address.

A. My name is Samuel S. Waters, and my business address is 9250 West Flagler Street, Miami, Florida 33174.

Q. By whom are you employed and what position do you hold?

A. I am employed by Florida Power & Light Company (FPL) as the Director of Resource Assessment & Planning.

Q. Please describe your duties and responsibilities in that position.

A. I manage the group that is responsible for the development of FPL's integrated resource plan and other related activities, such as analysis of demand-side management programs, system production cost projections, development of FPL's demand and energy forecasts, and the administration of wholesale power purchase agreements.

Q. Please describe your education and professional experience.

A. I graduated from Duke University with a Bachelor of Science Degree in Electrical Engineering in 1974. From 1974 until 1985, I was employed by the Advanced Systems Technology Division of Westinghouse Electric Corporation as a consultant in the areas of Transmission Planning and Power

System Analysis Software. While employed by Westinghouse, I earned a Masters Degree in Electrical Engineering from Carnegie-Mellon University in 1976.

I joined what was then the System Planning Department of FPL in 1985, working in the generation planning area. I became Supervisor of Resource Planning in 1986, and subsequently the Manager of Integrated Resource Planning in 1987, a position I held until 1993. At that time, I assumed the position of Director, Market Planning where I was responsible for oversight of regulatory activities for FPL's Marketing Department as well as tracking of marketing-related trends and developments.

In 1994, I became Director of Regulatory Affairs Coordination, where I was responsible for management of FPL's regulatory filings with the FPSC and FERC. In 2000, I assumed my current position. I am a registered Professional Engineer in the States of Pennsylvania and Florida and a Senior Member of the Institute of Electrical and Electronics Engineers, Inc. (IEEE).

Q. Have you previously testified before this Commission?

A. Yes. I have testified in several dockets related to FPL's resource plans including Docket 870197-EI, Petition of Florida Power and Light Company for Non-Firm Load Methodology and Annual Targets; Docket Nos. 890973-EI and 890974-EI, FPL's Petition To Determine Need for the Lauderdale and Martin Projects; Docket Nos. 900709-EQ and 900731-EQ, Joint Petition of

Indiantown Cogeneration Limited (ICL) and FPL to Determine Need for the ICL Facility; Docket No. 900796-EI, Petition for Approval of the Purchase of Robert W. Scherer Unit No. 4 from Georgia Power Company; Docket No. 910004-EU, Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Prices; Docket No. 910816-EI, Petition of Nassau Power Corporation to Determine Need; Docket No. 911103-EI, Complaint of Consolidated Minerals, Inc. (CMI) Against Florida Power & Light Company for Failure to Negotiate Cogeneration Contract; and Docket Nos. 920520-EQ and 920648-EQ, Joint Petition to Determine Need for Electric Power Plant to be located in Okeechobee County by Florida Power & Light Company and Cypress Energy Partners, Limited Partnership. I also submitted testimony in Docket No. 891049-EU, Revision to Cogeneration Rules.

Q. What is the purpose of your testimony?

A. My testimony addresses two major issue areas relevant to this case.

The first major area deals with power plant additions made to FPL's system since its last rate case and FPL's power plant performance improvement since 1988. In addressing this area, I will discuss:

- FPL's planning objective and process
- Improvements to FPL's fleet of power plants since 1988
- FPL's Production O&M Expenses
- FPL's resource addition since 1985 and,
- Generating unit additions scheduled in 2002

I will show that the additions made by FPL since 1985 were needed to maintain system reliability and are used and useful in providing service to FPL's customers. In addition, I will demonstrate that FPL has realized substantial savings for customers by maximizing the utilization of its existing generating units, and established itself as an industry leader in the operation of its plants. I will also show that FPL has reduced its fossil and nuclear generation non-fuel Operating and Maintenance (O&M) expenses, maintaining costs not only well below the Commission's O&M benchmark, but also below the levels approved by the Commission for 1988. My testimony documenting FPL's superior power plant performance while significantly reducing O&M costs is offered in support of the ROE adder sought by FPL in this proceeding. I will also show that the variance in O&M expense for Production-Other is justified.

The second major area presented in my testimony deals with the energy and demand forecasts utilized in the Minimum Filing Requirements (MFRs) filed in this case. In this area, I will discuss:

- The forecasting process and models used to project the number of customers, usage per customer, total sales and demand.
- The bases for the initial MFR forecast, filed in October, 2001 and,
- Revisions to the original forecast resulting from the events of September 11, 2001 and FPL's more current view of sales in 2002.

Based on this discussion of the energy and demand forecast, I will demonstrate that FPL's revised sales forecast, while reasonable, is optimistic and probably overstates FPL's 2002 and 2003 revenues.

Q. Are you sponsoring an exhibit in this case?

A. Yes. I am sponsoring an exhibit consisting of 26 documents attached to my direct testimony.

Q. Are you sponsoring any of the MFRs filed in this case?

A. Yes. I am sponsoring or co-sponsoring the MFRs shown in Document SSW-1.

<u>FPL's Planning Objective and Process</u>

Q. What is the objective of FPL's Integrated Resource Planning process?

The objective of the process can be stated simply as maintaining supply system reliability at the lowest cost or rate, while considering appropriate strategic issues such as fuel diversity and flexibility to respond to changing conditions. The first part of this statement, maintaining supply system reliability, is of primary importance in the planning process, driving the amount and timing of resource needs. FPL attempts to do this by adding resources in a manner that will reduce long-term costs to all customers in the form of rates. This primarily determines which resources are needed to meet the identified need. The selection of resources may also be influenced by the above mentioned qualitative strategic factors.

Q. How does the planning process address supply system reliability?

A. FPL has for many years used dual planning criteria of reserve margin and loss of load probability (LOLP). Use of this dual criteria approach ensures that adequate resources are not only available to meet the expected annual peak load, but also to meet daily peak conditions throughout the year.

The LOLP criterion used by FPL is 0.1 days per year, alternatively referred to as one day in ten years. This standard has been approved by this Commission in several previous proceedings as reasonable for planning purposes.

Prior to 1997 FPL employed a reserve margin standard of 15% of projected summer peak. This standard had also been reviewed and approved by this Commission in several proceedings. In 1997, responding to Commission concerns over reliability of the peninsular Florida supply system during winter peaks, FPL added a third criterion to its planning: a 15% winter peak reserve margin.

In 1999, as part of Docket No. 981890-EU, the Commission's Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida, FPL agreed to use a planning criterion of 20% reserve margin based on annual peak applied to planning years 2004 and beyond. This criterion has been applied in conjunction with LOLP since the 1999 planning cycle.

Q. Has the Commission reviewed and approved FPL's reliability criteria?

A. Yes, on several occasions FPL has presented the dual criteria discussed above, and the Commission has approved them as reasonable, including:

Docket	**Title**
890973-EI/890974-EI	Petition to Determine Need for Electrical Power Plant 1993-96
900709-EQ/900731-EQ	Indiantown Cogeneration, Ltd. Determination of Need
900796-EI	Petition for Approval of Purchase of Scherer Unit No. 4
910004-EU	Annual Hearings on Load Forecasts, Generation Expansion Plans and Cogeneration Process
910816-EQ	Nassau Power Corporation Determination of Need
920520-EQ	Cypress Energy Partners Determination of Need

The Commission has also had the opportunity to address FPL's entire planning process, including the reliability criteria used, in its annual review of utility Ten Year Power Plant Site Plans, as well as two comprehensive reviews during Conservation Goals hearings in 1994 and 1999.

Q. Why did FPL change its reserve margin criterion from 15% to 20%?

A. In 1998 the Commission staff expressed concern over the projected level of reserves in the state. The Commission initiated an investigation of reserve margins and, in that case, FPL and the other Investor-Owned Utilities in Peninsular Florida proposed and voluntarily agreed to begin using 20% of annual peak as a reserve margin criterion and to achieve this level of reserves by summer 2004. The Commission approved this stipulation in Order No. PSC-99-2507-S-EU. FPL continues to utilize a dual criterion approach to assessing system reliability, leaving in place the 0.1 days/year LOLP standard and a reserve margin standard of 15% of annual peak, until mid-2004 at which time the reserve margin standard becomes 20% of annual peak.

Q. Which reliability criterion is presently the controlling driver of the need for new resources?

A. Currently, FPL's need for new resources is driven by the reserve margin criterion. Use of LOLP alone would result in a lower level of resource additions. This relationship has reversed from those performed in the late 80s, when LOLP was the primary driver.

Q. Why is LOLP no longer the controlling driver of the need for new resources?

A. There are two reasons for this change over time. The first, and leading reason, is that FPL has made substantial improvements in the availability of its generating units since the late 80's. The second reason is, as previously mentioned, that FPL has changed its reserve margin targets from 15% of summer and winter peak to 20% of annual peak in mid-2004. In the interim period until 2004, FPL has attempted to raise its reserve margins toward the 20% level.

Q. Please describe how unit availability is used in the calculation of system LOLP.

A. In calculating LOLP, the expected daily peak demand is compared to the available generating capacity on a probabilistic basis. As an example of how this probabilistic determination of generating capacity works, consider two generating units, each having a 20% equivalent forced outage rate (EFOR). EFOR is a measure of the percentage of time a unit is expected to be out of service due to mechanical problems.

To keep the example simple, I will assume that the only outages these two units experience are forced outages, so they have an equivalent availability of 80% (100%-20% EFOR). This means that at any given point in time, there is an 80% chance that the unit will be in service, and a 20% chance it will be out of service.

Assuming that the two generating units in the example operate completely independently of one another, there are four possible combinations of operating states; both units on, the first unit on while the second is off, the second unit on while the first is off, and both units off. We can easily calculate the probabilities of each of these states by multiplying the individual unit probabilities.

State				
A	Both units on:	80% x 80%	=	64%
B	First on, second off:	80% x 20%	=	16%
C	First off, second on:	20% x 80%	=	16%
D	Both units off:	20% x 20%	=	4%
			Total	100%

To relate this information to LOLP, assume that the two units are 60 MW each, and our expected daily peak is 100 MW. This is equivalent to a 20% reserve margin for the day (120 MW capacity/100 MW load). We now look at the probability of those states above that would result in insufficient capacity to meet the peak load of 100 MW. State A yields 120 MW, which is sufficient to meet expected load. States B and C yield only 60 MW, and each has a 16% probability of occurrence. State D yields zero MW and has a 4% chance of occurrence. In order to determine the probability that the electrical demand cannot be met, one must sum the probabilities of states B, C and D. This sum is 36%. Thus, the contribution for this single day towards LOLP, which is an annual number, would be 36% or 0.36. This calculation would be repeated for each of the 365 days in a year to yield the final LOLP result.

Q. How would improving unit availability affect the LOLP result?

A. If I were to improve the reliability of the generating units by decreasing the forced outages to 10% (10% EFOR), my generating state table would change to:

State

A	Both units on:	90% x 90%	=	81%
B	First on, second off:	90% x 10%	=	9%
C	First off, second on:	10% x 90%	=	9%
D	Both units off:	10% x 10%	=	1%
			Total	100%

Now the sum of the probabilities of states B, C and D is 19%, or the contribution to LOLP is 0.19.

Q. What are the practical implications of this improvement in availability?

A. In simple terms, improving generating unit availability, by reducing LOLP, translates into an increased value for existing generation, and a decreased need for new capacity. Each 1% improvement in availability roughly translates into a 1% increase in available capacity, e.g., for 10,000 MW of generating capacity, a 1% availability improvement is equivalent to approximately 100 MW of additional generation. From a planning perspective, as long as LOLP is the driver in determining future resource needs, this is 100 MW of new generation I would not have to add to meet expected load. I will discuss later in my testimony how FPL has improved generating unit availability and provided a tremendous benefit to its customers.

Q. How does the planning process address resource alternative economics?

A. In general terms, the objective of the economic analysis is to identify the combination of resources that results in the lowest cost (i.e., electric rates) to customers. Alternatives may be examined under a number of different scenarios to ensure a robust solution. Other factors, such as technology risk, environmental risk, flexibility to respond to changing conditions and security of fuel supply, may also be examined to differentiate between alternatives when economic differences are small.

The comparison of competing alternatives is performed reflecting all associated quantifiable costs, both direct and indirect. For example, in comparing supply alternatives, i.e., competing generating units, the direct costs would include capital, fixed Operating and Maintenance (O&M) expenses, variable O&M expenses and fuel costs. An indirect cost would be the change in the fuel costs of other, existing generating units when the new unit is added to the system. This last item might either be a cost (increase in other units' fuel costs) or a benefit (reduction in other units' fuel costs). A comparison of the total of these costs, referred to as revenue requirements, is done over time, and done on a net present value of revenue requirements (PVRR) basis.

Using competing new generation unit alternatives as an example, the generating alternative with the lowest PVRR over the life of the project is favored, although other factors must be considered, as I mentioned above.

Q. Is the same comparison done when the alternatives are demand-side management (DSM) programs?

A. Yes, in the sense that the sum of all quantifiable direct and indirect costs are compared. However, when DSM programs are compared, there must also be a recognition of the fact that in most cases kWh sales to participating customers are reduced, shifting the contribution those sales make to existing costs to non-participating customers, increasing their rates. This method of comparison of DSM is known as the Rate Impact Methodology (RIM) test, and it is the methodology employed by FPL. It allows FPL to analyze DSM on an identical basis (i.e., impact on electric rates) to generating alternatives.

Q. Has the Commission approved the use of the RIM test for comparison of DSM programs?

A. Yes. The RIM Test has been reviewed thoroughly and approved in Order No. PSC-94-1313-FOF-EG and reiterated in Order No. PSC-99-1942-FOF-EG.

Q. Has FPL employed the processes you have described to identify needed resource additions since its last rate case?

A. Yes we have, for both generation and DSM additions. I will review those prudent additions and show those additions have contributed to system reliability and are used and useful in serving FPL's customers. However, before I discuss added resources, I would like to present the actions FPL has taken with regard to its existing fleet of generating resources. These actions have improved operational performance to the point where FPL's units are among the best in the industry.

FPL's Improvement in Plant Performance

Q. What indicators does FPL use to measure the performance of its fleet of fossil-fuel generating units?

A. FPL uses a number of indicators to measure the performance of its fossil-fuel units. They include Equivalent Availability Factor (EAF) to measure the unit's availability, Equivalent Forced Outage Rate (EFOR) to measure the unit's reliability, OSHA Recordables to determine how safely work is performed, and heat rate to measure efficiency in the use of fuel.

Q. Please define Equivalent Availability Factor (EAF) and Equivalent Forced Outage Rate (EFOR).

A. Equivalent Availability Factor (EAF) is a measure of the generating unit's capability to provide electricity throughout the year, regardless of whether the generating unit is actually called upon to provide electricity. EAF is reported in terms of the hours in a given period (e.g., a year), that a generating unit is available to deliver electricity, as a percentage of all the hours in the period. FPL strives for, and has achieved, a high EAF.

Equivalent Forced Outage Rate (EFOR) is a measure of a generating unit's inability to provide electricity when called upon. EFOR is reported in terms of the hours when a generating unit could not deliver electricity as a percentage of all the hours during which that unit was called upon to deliver electricity. FPL strives for, and has achieved, a low EFOR.

The North American Electric Reliability Council (NERC) formulas for calculating EAF and EFOR are shown in Document SSW-2.

Q. Please show how the EAF of FPL's fossil-fuel units has improved over time.

A. As shown in Document SSW-3, the EAF of FPL's fossil-fuel units has improved significantly over time, from 79.8% in 1988 to 89.6% in 2000 and 90.1% in 2001.

Q. How does the EAF of FPL's fossil fuel units compare to that of others in the industry?

A. As shown in Document SSW-4, in 1999 the EAF of FPL's fossil-fuel units was 88.5%. This placed FPL's performance in the top decile of the twenty-two largest utilities, that is, those with more than 5,000 MW of installed fossil-fuel generation capacity. FPL's EAF performance in 1999 was also 5.1 percentage points better than the median availability (83.4%) of all fossil utilities in the NERC database. In 2000 FPL's EAF improved to 89.6%, better than the best large utility in the 1999 database. In 2001 FPL maintained its "best-in-class" position with an EAF of 90.1%.

Q. Please show how the EFOR of FPL's fossil-fuel units has improved over time.

A. As shown in Document SSW-5, the EFOR of FPL's fossil-fuel units has improved significantly over time, from 6.4% in 1988 to 1.4% in 2000 and 1.6% in 2001.

Q. How does the EFOR of FPL's fossil fuel units compare to that of others in the industry?

A. As shown in Document SSW-6, in 1999 the EFOR of FPL's fossil-fuel units was 1.7%. This placed FPL's performance as "best-in-class" among the twenty-two utilities with more than 5,000 MW of installed fossil-fuel generation capacity in the 1999 database. FPL's EFOR performance in 1999 was also 5.6 percentage points better than the industry average EFOR of 7.3% for all fossil utilities in the database. In 2000 FPL's EFOR improved further to 1.4%. In 2001 FPL's EFOR was 1.6%.

Q. What is the source of the data FPL uses to compare its EAF and EFOR performance to that of other utilities?

A. FPL obtains annual EAF and EFOR data from NERC to compare its performance to that of other utilities. This annual data becomes available approximately 12-15 months after the end of each calendar year. It is expected that other utilities' results for the year 2000 will be available by the spring of 2002.

Q. What relevance does FPL's EAF and EFOR performance have as it relates to this case?

A. The two direct benefits associated with FPL's excellent EAF and EFOR performance are reduced need for new capacity additions and fuel savings. Each 1% change in availability is equivalent to approximately a 1% change in available capacity. FPL's fossil-fuel generation summer peak capacity by the summer of 2002 will be 14,976 MW. Therefore, 1% in availability for FPL's fossil-fuel fleet in 2002 will be equivalent to about 150 MW.

As stated above, the difference between FPL's availability in 1999 (88.5%) and the industry average availability (83.4%) is 5.1 percentage points. This difference in availability, applied to FPL's 14,976 MW of summer peak fossil-fuel generating capacity in 2002 would be equivalent to 764 MW of installed generation using the 1999 EAF differential. If we apply the differential in FPL's own EAF performance between 1988 (79.8%) and 2001 (90.1%), the equivalent capacity would be 1,543 MW, equivalent to 10.3% of FPL installed fossil-fuel generating capacity in 2002. Having this additional available capacity can help defer costs associated with new generation additions, be they FPL-owned, or purchased power.

This incremental generation capacity, made available by FPL's excellent performance, can also be used to make wholesale power sales, which result in a reduction in fuel cost to FPL's retail customers, since a large portion of the gain from such sales is applied as a credit to fuel expense.

In addition, having greater availability means that the most efficient generating units will be available to operate a greater part of the time, thus reducing the need to substitute less efficient units to meet customer needs, and thereby avoiding higher fuel costs associated with operating the less efficient units. A partial measure of the fuel savings can be obtained by considering the net fuel savings calculated between 1990 and 2000 as part of the Generation Performance Incentive Factor. By operating the fossil-fuel generating units with availability and heat rate better than target, FPL saved its customers over $5.2 million, net of rewards. Since the targets are made more demanding as a result of good performance, this figure understates the total savings achieved as a result of FPL's improvement in EAF.

From a more general perspective, FPL's excellent performance in EAF and EFOR, combined with its equally excellent performance in safety and O&M costs, is indicative of a well managed organization, with knowledgeable, dedicated employees, all committed to meet our customers' energy needs in a cost-effective manner.

Q. Has FPL taken other actions related to its fossil-fuel units to improve unit performance and avoid the need for new generating capacity?

A. Yes, FPL has taken steps to increase confidence in the reliability of the peaking capability of several of its generating units. A program known as Perfect Execution of Peaking Operation (PEPO) was implemented to enable FPL confidently to rely on high levels of output from the fossil fuel units under peaking conditions. The PEPO program consisted of engineering analysis, inspection, and testing of units to determine the reliable amount of peaking capacity available from each fossil generating units. This peaking capacity had been available in the design of the existing generating units but was not counted on prior to the PEPO program. The PEPO program raised FPL's level of confidence in the reliability of these peaking MW to the point they could be included in the capacity plan in the 1995 FPL Ten Year Power Plant Site Plan and thereafter. This program has made available to FPL 560 MW of peaking capability.

Q. Please describe what you mean by "OSHA Recordables."

A. OSHA Recordables are all work-related deaths and illnesses and those work-related injuries which result in: loss of consciousness, restriction of work or motion, transfer to another job, or require medical treatment beyond first aid, and which must therefore be reported to the Occupational Safety & Health Administration (OSHA). FPL keeps a record of all such incidents, referred to as "OSHA Recordables," as a measure of how safely work is performed at its fossil-fuel plants.

Q. Please show how the annual number of OSHA Recordables at FPL's fossil-fuel units has changed over time.

A. As shown in Document SSW-7, FPL's OSHA Recordables for fossil units have decreased from 154 in 1988 to only 7 in 2001. This remarkable improvement reflects not only the tenacity of FPL's safety effort and the strength of FPL's safety culture, but also the broader discipline and effective organization which FPL applies to performance of work at its fossil-fuel plants. While this improvement in safety has been a significant achievement, our goal remains to have zero injuries.

Q. How does FPL's fossil unit safety performance compare to other utilities?

A. As shown in Document SSW-8, in recent years FPL has had the lowest number of OSHA Recordables among utilities with more than 7,000 employees that have responded to the survey conducted and published by the Edison Electric Institute (EEI). This is such an essential aspect of FPL's culture that every reasonable effort is being made to achieve our goal of zero OSHA Recordables, as well as achieving, among all employees and their families, a universally held safety culture that extends beyond the workplace to their homes and all other activities.

Q. Why is safety such an important issue at FPL?

A. It is important for three reasons. First, because it is the right thing to do, to ensure that all our employees and contractors avoid injuries and return safely to their families. Second, because personal interdependence and mutual support among our employees, and the level of individual discipline and attention to detail required as part of an effective safety culture, are equally required to perform quality work, so performance improves as a byproduct of the safety culture. Third, because avoiding injuries reduces costs, which benefits our employees, our contractors, our customers, and our shareholders. One readily quantifiable cost reduction is in the area of Wrap-Up Insurance premiums to cover FPL's contractors at FPL's plants. These annual premiums have been reduced from $1.4 million in 1996, to $425,000 in 2001, due to the improved safety performance of our contractors, resulting from their adoption of FPL's safety culture and processes at FPL's insistence.

Q. Please show how the efficiency of FPL's fleet of fossil-fuel generating units has changed over time.

A. The trend in the efficiency of FPL's fossil-fuel generating units from 1990 to the present, and projected to 2004 is provided in Document SSW-9. The measure of efficiency reflected in this graph is Net Heat Rate, calculated by dividing the total Btu of fuel consumed each year in FPL's fossil-fuel units, by the kWh of electricity delivered to the grid from those units. In 1990 the average heat rate for FPL's fossil-fuel units was 10,060 Btu/kWh, compared to 10,380 for the average of all electric utilities. By 2002 FPL's average heat rate will have improved by 5% to 9,547 Btu/kWh, while the industry average reported by Platts-RDI will have deteriorated by 3% to 10,648 Btu/kWh.

By 2003, as a result of the efficiency improvements associated with the repowering of Ft. Myers Units 1 and 2 and Sanford Units 4 and 5 to combined cycle units, FPL's average heat rate is projected to improve by an additional 12%, to 8,358 Btu/kWh.

Q. Has FPL shown similar improvements in its nuclear plant operations?

A. Yes. Between 1988 and 2000, FPL has improved its overall nuclear unit equivalent availability from 75% to 93%, as shown in Document SSW-10. Using the existing nuclear capacity of 2,939 MW as a reference (summer ratings), an 18% increase in availability equates to approximately 529 MW of additional capacity value.

Q. Can you show other indicators for nuclear units comparable to the fossil unit indicators?

A. Yes. Document SSW-11, shows EFOR data for FPL's nuclear units versus the top quartile in the industry. The range of variance is very small, and performance of nuclear units is more dependent on outage scheduling than for fossil units, but this shows that FPL's performance over the past several years has been outstanding.

Document SSW-12 shows that the nuclear OSHA Recordables approach top quartile performance.

Q. What other indicators can be used to measure nuclear performance?

A. Two additional indicators unique to nuclear operations are used to measure the performance of FPL's nuclear plants: Refueling Outage Duration and World Association of Nuclear Operators (WANO) rating. The WANO rating is a weighted average rating of 11 operational measures for a nuclear unit and is the most significant measure of overall performance.

Document SSW-13, shows FPL's nuclear refueling outage durations versus the U.S. industry top quartile performers, demonstrating that FPL is at or near top quartile performance level. Document SSW-14, shows the FPL Turkey Point and St. Lucie WANO ratings for 1996 to date. This exhibit demonstrates that FPL's nuclear operations are performing above the top quartile level overall.

Q. Can the benefits to FPL's customers of FPL's superior operation be quantified?

A. Yes. Both capacity and fuel benefits can be estimated based on availability improvement, and certainly system fuel benefits can be inferred from FPL's Generation Performance Incentive Factor (GPIF) filings.

Regarding capacity benefits, the sum of the MW avoided due to the fossil and nuclear availability improvements since 1990 is roughly 2,072 MW. Estimates for new combined cycle capacity, which I will use as a proxy for what would have been built had FPL not improved availability, run between about $400 and $500 per kW. Using the low end of this range, the avoidance of 2,072 MW of new combined cycle is equivalent to about $829 million of avoided capital investment.

Looking again at FPL's history in GPIF, there has been a net fuel savings of more than $49 million since 1990. These fuel savings, of course, include heat rate improvements at existing units, but availability improvements make up the bulk of the savings. The $49 million of fuel savings is conservative, given the ratcheting of the GPIF targets as improvement occurs.

Another way to estimate fuel savings is to look only to the nuclear units and calculate their impact. Earlier I used a total of 2,939 MW of existing nuclear capacity (summer). Based on this capacity, a 1% availability change represents 257,456 MWh of generation. If we assume that any change in nuclear generation results in an equal and opposite change in FPL's oil/gas fired fossil generation, then an increase of 257,456 MWh of nuclear generation will result in a decrease in oil and gas fired generation. For the example, I will assume that nuclear fuel costs $4/MWh, while oil and gas fuel costs roughly $30/MWh. Thus, each additional MWh of nuclear generation saves roughly $26/MWh in energy costs.

Since nuclear generation has improved its availability by 18% since 1988, I can estimate that customers are currently saving about

$26/MWh x 257,456 MWh/year x 18% = $120.5 million/year

in fuel expense due to the availability improvements. This is greater than the estimate provided using GPIF, which is to be expected, since GPIF does not give credit for reductions in planned outages. GPIF also moves the target as improvements occur, ratcheting the target upward and reducing future rewards. In either case, it is clear that FPL's customers have enjoyed substantial fuel benefits, as well as capacity benefits, as a result of FPL's actions to improve generating unit availability.

Q. Has FPL taken other actions to improve unit performance and avoid the need for new generating capacity?

A. Yes. FPL has completed a project to increase the output of its Turkey Point nuclear units.

Q. Please describe the Turkey Point nuclear uprating.

A. In 1996 FPL increased the rating of its Turkey Point nuclear units from 666 MW (summer) each to 693 MW (summer) each. Similarly to EAF improvements, this uprating was accomplished through engineering studies which suggested the unit could be operated at a higher level, and obtaining NRC approval to do so. No significant physical changes to the plant were required. This increase provides both capacity and fuel benefits. The additional 54 MW of capacity provides direct avoidance of an equivalent amount of new capacity. The energy from this additional capacity displaces more expensive fossil fuels and provides additional savings.

The fuel-related savings of this project were presented to the Commission in FPL's Fuel Cost Recovery Proceeding, Docket No. 960001-EI and expenses related to the project were approved for recovery in Order No. PSC-96-1172-FOF-EI.

Q. Has FPL taken any other actions to avoid the need for new generating capacity?

A. Yes. FPL has implemented a number of DSM programs to defer or avoid construction of new generation. I will discuss these programs in the following section on resource additions since 1985.

Q. Are there other measures FPL can utilize to maintain reliability beyond generation and DSM programs?

A. Yes. While the 20% reserve margin represents a very high level of system adequacy, resulting in more than 3,700 MW of reserves (2002 summer, per 2001 Ten Year Site Plan), FPL has other measures at its disposal to maintain reliability, which are not now included in those reserves. Included in these measures are: Curtailable Load, System Voltage Reduction and SCRAM of load control.

Curtailable load is a program in which customers agree to reduce usage upon request in exchange for a reduced rate. Currently, this program represents about 39 MW of demand reduction potential (summer). It is not included in the current reserves for two reasons: customers control their own demand reduction and there is no notice provision for customers to leave the program. Both of these factors increase uncertainty about relying on the resource.

System voltage reduction is a measure that can be implemented by the system operator in the event of a capacity shortage. The reduction capacity varies by season, but tests conducted by FPL show a net demand reduction capability of approximately 130 MW.

The third measure, SCRAM of the load control program, is implemented at the system control center also. While normal implementation of load control involves cycling of controlled end-uses, e.g., turning off air conditioning for 15 minutes per half hour in coordination with other controlled customers, a SCRAM simply shuts down all controlled devices for the duration of a system emergency. This measure can account for as much as an additional 800 MW of demand reduction beyond the reduction achieved by normal control.

Thus, looking at the 2002 summer expected peak demand, FPL has, in addition to the 3,700 MW of reserve capability, additional capability of nearly 1,000 MW of operational measures upon which FPL can rely.

Q. In Order No. 13537, the Commission stated, "[W]e shall request that the Company establish why the curtailable service should not be discontinued in the Company's next rate case." How has FPL addressed this issue?

A. FPL is in the process of preparing a separate petition to modify its curtailable service.

Q. What is your summary view of the expected reliability of FPL's supply system?

A. FPL has maintained an extremely reliable power supply system for many years, and done so while decreasing the base rates charged to its customers. It has been 12 years since the last customer outages due to a generation deficiency. Over the past decade, FPL has improved the operating performance of its generating units and increased the available capacity from those units. To ensure continued reliable operation, FPL has adopted a more stringent reliability standard, and continues to maintain substantial operational measures to back up its capacity resources. I believe that FPL has done an outstanding job of maintaining system reliability without the need to raise rates, even though some significant capacity and DSM resources have been added since FPL's last rate case. I will discuss those additions in a following section of my testimony.

FPL's Production O&M Expenses

Q. While reliability has improved, what has been FPL's experience with O&M expenses over the same period?

A. Since 1988 FPL's total non-fuel production expense for fossil units, as measured in cents per kWh, has declined from 0.61 cents per kWh to 0.27 cents per kWh in 2000. Nuclear non-fuel expense has declined from 1.20 cents per kWh to 0.98 cents per kWh over the same period. Thus, FPL has achieved its significant reliability improvement while significantly decreasing its O&M expenditures on a per unit basis. In fact, as demonstrated by the cents per kWh figures, fossil non-fuel production expense has declined by nearly 56%, while nuclear has declined by 18%.

Q. How does FPL's change in O&M expense compare to the Commission's benchmark?

A. Overall, the production O&M is well under the Commission benchmark, which employs 1988 as the base year. For this comparison, I refer to Mr. Davis' updated O&M benchmark calculation shown on Document KMD-8, which shows the following:

	2002 O&M Exp. ($000)	2002 Benchmark ($000)	2002 Adjusted Benchmark Variance ($000)
Production-Steam	121,683	248,982	(127,299)
Production-Nuclear	263,244	440,284	(177,040)
Production-Other	36,728	27,716	9,012
Total	421,655	716,982	(295,327)

It should be noted that for these categories, the 2002 benchmark is developed using CPI only. This comparison shows that FPL's projected 2002 Production–Steam expense is more than $127 million under the benchmark, while Production-Nuclear is more than $177 million under the benchmark. While in this comparison FPL's Production-Other expense shows a small positive variance, the overall 2002 O&M Production expense is more than $295 million lower than the Commission benchmark. For fossil units alone, combining the Production-Steam and Production-Other functions, FPL is more than $118 million below the benchmark.

Q. Aside from the Commission's O&M benchmark test, what other measure do you have of the reasonableness of FPL's Production-Other non-fuel O&M expenses?

A. Perhaps the best measure of the reasonableness of FPL's 2002 projected Production-Other non-fuel O&M expenses is that FPL projects 2002 total non-fuel O&M production expenses below the level of total Production-Other non-fuel O&M expenses that the Commission approved for 1988. This is shown in the table below:

	1988 PSC Approved Production O &M Exp. ($000)	2002 Projected Production O&M Exp. ($000)
Steam	161,927	121,683
Nuclear	286,342	263,244
Other	18,025	36,728
Total	466,294	421,655

FPL projects to spend $44.6 million less in production non-fuel O&M in 2002 than the level the Commission approved for 1988.

What makes this all the more remarkable is that between 1988 and 2002 the CPI rose 54% and FPL will have added over 4,500 MW of additional capacity. So, despite inflation increases of 54% and the addition of significant new generating capacity, FPL will be spending approximately $44.6 million less in Production non-fuel O&M expenses in 2002 than the level of expenses the Commission approved for 1988. Considering FPL's extraordinary power plant performance improvements and resulting customer savings due to avoided capacity and fuel costs during this same period, this cost reduction is truly remarkable.

Q. Why does Production–Other show a positive variance in the Commission's benchmark test?

A. There are several reasons the projected Production-Other expenses exceed the Commission's O&M benchmark test.

First, since 1988, the base year for the O&M benchmark test, FPL has repowered its Lauderdale Units 4 and 5, Ft. Myers Units 1 and 2 and Sanford Units 4 and 5. In 1988 all those units were reflected in Production-Steam expenses because each of those units burned a fossil fuel to make steam directly for the production of electricity. In FPL's 2002 projection of O&M expenses, the O&M expenses for the repowered Lauderdale and Ft. Myers units are reflected in the Production-Other function, for they now operate as combined cycle units. If the benchmark calculation were properly adjusted to reflect this conversion of plants from the Production-Steam function to the Production-Other function, there would be no positive variance.

Second, unlike other functions in the Commission benchmark test, the O&M expenses in the Production functions are escalated only by CPI, not CPI plus customer growth. It was recognized that expenses for existing plants would not be affected by customer growth. Thus, expenses for plants added since the base year have been recognized as a justification of expenses exceeding Production benchmarks. Even if FPL did not make the O&M benchmark adjustment discussed above to move repowered units from Steam-Production to Production-Other, FPL can justify its entire variance by the addition of new plants necessary to meet customer growth.

Q. Please explain how recognizing in the O&M benchmark calculation the conversion of FPL's repowered units from the Production-Steam function to the Production-Other function results in there being no positive O&M expenses variance in the Production-Other function.

A. There is a simple way to demonstrate the impact of switching units between functions. Since the Lauderdale and Ft. Myers units will be accounted for as Production-Other, I will redo the benchmark showing their 1988 O&M levels as Production-Other, removing them from Production-Steam.

Using FPL's 1988 FERC Form 1 data for these units, which I have summarized as my Document SSW-15, I calculate the following non-fuel O&M costs in 1988:

Lauderdale 4, 5	$4,800,105
Ft. Myers 1, 2	$7,929,001

Subtracting the O&M for Lauderdale and Ft. Myers from Production-Steam and adding it to Production-Other results in the following base year (1988) values:

	Benchmark Year Allowed O&M From MFR Schedule C-55 (000's)	Adjusted Value (000's)
Production-Steam	161,927	149,198
Production-Nuclear	286,342	286,342
Production-Other	18,025	30,754

Now, using these revised base year values, I can calculate a new 2002 benchmark value using the CPI compound multiplier from MFR Schedule C-56 and reproduce the table I previously presented:

	2002 O&M Expense ($000)	2002 Adjusted Benchmark ($000)	2002 Adjusted Benchmark Variance ($000)
Production-Steam	121,683	229,409	(107,726)
Production-Nuclear	263,244	440,284	(177,040)
Production-Other	36,728	47,288	(10,560)

From this it is clear that while there may be other factors involved in the appearance of a benchmark variance, the entire apparent variance is more than explained by capacity moving from the Production-Steam function to the Production-Other function. As shown, the Production-Other function is well below its benchmark.

Q. Please explain your earlier statement that FPL can justify its entire Production-Other variance by the addition of new power plants.

A. As the Commission explained in its order in FPL's 1984 rate case, the O&M benchmark for the Production functions is calculated by escalating the base year's level of expenses only by CPI, not CPI and customer growth:

> However, the record in this case reveals that allowing both CPI and customer growth is not appropriate for all categories of expenses. Specifically, we find that production plant O&M should only be inflated for the CPI increases and not for customer growth. This is so, because, unlike customer or line crew personnel whose numbers have a logical and fairly direct correlation to the number of customers served, generating plant is built to serve a certain maximum load and its non-fuel O&M expenses do not rise as a result of new customers being added to the system, but, rather, rise when new plant is built.

This recognizes that customer growth does not affect non-fuel production costs for existing plants.

As the Commission further noted in that same rate case order, new plant additions made to meet customer growth are an appropriate justification for exceeding the benchmark. In that case the Commission accepted as a justification for exceeding the benchmark O&M expenses associated with new plants brought into service after the base year – St. Lucie Unit 2 and Martin - as well as with plants brought out of cold standby that had not operated in the base year used to develop the benchmark.

Q. What are the projected non-fuel O&M expenses for the new plant additions that were not in 1988 Production – Other expenses?

A. The non-fuel O&M expenses for new or repowered plants included in FPL's 2002 budget that were not in FPL's 1988 Production – Other expenses are shown below:

Repowered Units	**Budgeted O&M ($000)**
Lauderdale 4 and 5	$7,507
Ft. Myers 1 and 2	$4,771
New Units	
Martin 3 and 4	$5,439
Martin 8A and 8B	$436

Each of these plants was added to meet increased demand on FPL's system. As shown, expenses for new unit additions ($18,153,000) more than justify the Production - Other O&M benchmark variance ($9,012,000).

Q. Independent of your justification of the benchmark variance in the Production–Other, what assurance can you give the Commission that FPL's projected 2002 Production–Other expenses are reasonable?

A. There are other measures that show the reasonableness of FPL's projected 2002 Production–Other O&M expense. First, FPL's cost per kWh for Production–Other non-fuel expenses base is projected to decline from 0.82 cents/kWh in 1988 to 0.14 cents/kWh in 2002. This is an 83% decline in Production–Other costs. Second, FPL's total 2002 non-fuel O&M expenses for plants that existed in 1988 are projected to be lower than FPL's actual 1988 total non-fuel O&M expenses. Given the 54% rise in inflation since 1988, this nominal decline is remarkable.

Q. Should the variance in Production–Other expense be a concern?

A. No. As I have shown, the entire variance can be justified two separate ways: first, as a change in accounting for units on FPL's system that were not included in FPL's Production-Other function when the base year expense was set, and second, due to the addition of new plants. Thus, the variance is completely justified.

Q. Please summarize FPL's power plant performance and cost control.

A. FPL's overall performance in fossil and nuclear plant operations is exemplary. FPL has established itself as an industry leader in power plant operation, while significantly driving down O&M costs. Mr. Dewhurst has proposed an ROE adder that relies, in part, on this superior performance.

FPL Resource Addition Since 1985

Q. What new resources has FPL added to its system since 1985?

A. There are three areas where FPL has added new, cost-effective resources since 1985:

- Demand-side management, which includes conservation and load control;
- Power purchases, which includes purchases from Qualifying Facilities (QFs) and other power suppliers and;
- New generation, which includes repowering, construction of new power plants, and acquisition of existing power plants.

Q. Please describe the demand-side management additions.

A. Referring to FPL's 2001 Ten Year Site Plan, Schedule 3.1, from 1991 through 2000 FPL implemented approximately 1,058 MW of summer peak reduction through conservation. An additional 1,223 MW of demand reduction was accomplished through residential and commercial/industrial (C/I) load control programs. The total of 2,281 MW of demand reduction during that period avoided the need for more than 2,600 MW of new capacity, based on maintenance of a 15% reserve margin.

Q. Load control appears to be a significant part of FPL's overall DSM efforts. What programs does FPL offer?

A. There are four programs which comprise FPL's load control efforts:

- Residential Load Management (On Call), which offers control of major appliances/household equipment in exchange for monthly electric bill credits;
- Business On Call, which offers control of central air conditioning units to both small, non-demand-billed and medium, demand-billed commercial/industrial customers in exchange for monthly electric bill credits;
- Commercial/Industrial Load Control, which controls customer loads of 200 kW or greater in exchange for monthly electric bill credits. This program is currently closed to new customers; and
- Commercial/Industrial Demand Reduction, a new program in 2001, which is similar in application to the C/I Load Control Program described above.

The Commission has approved each of these programs, finding them cost-effective, and periodically has reviewed their cost-effectiveness.

Q. How much demand reduction has been achieved by these programs?

A. Through December 2001, the Residential Load Management Program has resulted in 801 MW of summer peak reduction. C/I Load Control has added 449 MW, while Business On Call has provided 32 MW. The Commercial/Industrial Demand Reduction program is new for 2001, but has added 3 additional MW.

Q. Has FPL's reliance on load control programs to provide a portion of reserves lessened system reliability?

A. No. Load control has proven to be an effective, reliable resource. Customer satisfaction with FPL's programs is high, as evidenced by low turnover rates in the residential programs and a lack of customer complaints in C/I programs. The MW of demand reduction when implemented have proven to be predictable and reliable.

Because FPL carefully considered customer acceptance of control events, as well as other factors such as rebound and limits on the amount of control possible, its load control programs are highly effective. However, FPL is currently approaching the maximum cost-effective level of its current program offerings. Thus, while load control currently contributes a significant portion of total reserves, that portion will decline as FPL adds new generating resources.

Q. Please describe the power purchases made since its last rate review.

A. In 1985 FPL had purchased capacity from Tampa Electric Company's Big Bend Unit No. 4 and from the Southern Company under a Unit Power Sale (UPS) Agreement. The Big Bend purchase ended in 1987. FPL's initial UPS agreement ended in 1995. FPL had also contracted for 445 MW of Qualifying Facility (QF) capacity (1995 summer level).

In 1988 FPL entered into a new UPS agreement with the Southern Companies under which FPL purchases 931 MW through May 2010. FPL also entered into a joint agreement with the Jacksonville Electric Authority (JEA) to co-own the coal-fired units at the St. Johns River Power Park (SJRPP), as well as purchase output from those units under a long-term power purchase agreement. FPL received 382 MW of capacity from this power purchase arrangement over the 30 year life of the units as well as owning a 254 MW share of the units. In addition to the above purchases, FPL has continued to contract with QFs, currently purchasing 886 MW (2001 Summer Level) of firm capacity from QFs. FPL has also entered into short-term agreements to purchase power from several non-utility generators in the 2002-2006 time frame.

Q. Are the costs of DSM programs and power purchases recovered through base rates?

A. No. Both DSM costs and power purchase costs are recovered through clause mechanisms. However, by pursuing these cost-effective alternatives to new power plant construction, FPL has reduced overall costs to customers and avoided capital additions to its rate base. The Commission, via its annual reviews of clause expenditures, as well as its DSM Goals hearings and QF contract approval hearing, has reviewed and approved both the DSM implementation plan and a number of the power purchases made since the last rate case.

Q. That brings us to the addition of new generating capacity. What new units has FPL added to its system since the last rate review?

A. Since 1985 through 2001 FPL has made the following capacity additions:

Units(s)	In-Service Year	Incremental Capacity, MW
SJRPP 1, 2	1987/88	254 (Ownership)
Lauderdale 4, 5 Repowering	1993	580
Martin 3, 4	1994	948
Scherer 4	1992	658
Martin Combustion Turbines	2001	298
Ft. Myers Combustion Turbines*	2001	894

*(Initial Phase of Repowering)

Q. Are these units used and useful on FPL's system?

A. Yes. Each of these units has, and continues to run, at a high capacity factor indicating that they are useful in providing low cost energy to FPL's system. Below is a summary of the capacity factors of each of these units from time of being placed in-service to the end of November, 2001.

Units(s)	**Capacity Factor**
SJRPP 1, 2	86%
Lauderdale 4, 5	84.5%
Martin 3, 4	90%
Scherer 4	78%
Martin 8A, 8B	14% (peaking units)

Q. Are these units also currently used to maintain system reliability?

A. Yes. Without any of the above-mentioned units, FPL would currently fall below a 20% reserve margin, reducing overall system reliability.

Q. Do these units contribute to fuel diversity and less dependence upon oil?

A. Yes. In 1984 FPL reported 1984 actual fuel usage of:

Nuclear	32%
Coal	-
Oil	26%
Gas	22%
Interchange (and QFs)	20%

(Source: 1985 FPL Ten Year Site Plan)

Interchange was primarily coal-based as part of FPL's Oil Backout purchases. The SJRPP units were the first FPL-owned coal-based resources added to the system.

The 2002 projected fuel mix reported by FPL is:

Nuclear	24%
Coal	6%
Oil	16%
Gas	36%
Interchange (and QFs)	18%

(Source: 2001 Ten Year Site Plan)

The numbers show that while FPL's Net Energy for Load has grown by more than 80%, the fuel mix has remained balanced, without overreliance on any one source, particularly oil. FPL's mix in 1980, for example, showed 50% of generated energy coming from oil. FPL took a number of actions in the early 1980s to reduce its dependence on oil, including construction of two 500 kV lines to Georgia, the addition of the St. Lucie 2 nuclear unit, and purchases of coal-based energy from the Southern Companies. Of course, reduced dependence on oil has been Florida state policy since the passage of FEECA.

Q. Please summarize FPL's power plant additions since its last rate case.

A. From 1985 through 2001 FPL has added approximately 3,600 MW of new, owned, generating capacity, while decreasing its base rates. FPL will add nearly 1,200 additional MW in 2002, which I will discuss later in my testimony. During this time, FPL has actually increased supply system reliability by increasing its reserve margin criterion and adding new resources to meet that criterion. FPL has also maintained a diverse fuel mix throughout, and improved the efficiency at which it generates electricity, decreasing its overall system heat rate from 10,242 BTU/kWh in 1984 to 9,547 BTU/kWh in 2002. In other words, FPL customers receive about 7% more electricity per unit of fuel burned than they did in 1984. This extraordinary performance has benefited FPL's customers.

<u>Unit Additions Scheduled in 2002</u>

Q. Does FPL have plans to bring new capacity in service during 2002?

A. Yes. FPL will complete the repowering of its existing Ft. Myers Units 1 and 2, which began in late 2000 with the addition of several simple cycle combustion turbines. When completed, this repowering will add approximately 929 MW of summer (1,073 MW winter) capability to FPL's system. The total installed cost for the project is currently expected to be approximately $506,000,000. The project will convert the previously existing oil-fired units, with a total capability of 543 MW (summer), to natural gas-fired combined cycle operation. The effective heat rate of that existing capacity will decrease from approximately 10,000 BTU/kWh to roughly 6,830 BTU/kWh, more than a 30% improvement in efficiency. Air emissions from the plant will also be reduced.

FPL will also complete the repowering of its Sanford Units 4 and 5, converting these existing oil and gas-fired units to gas-fired combined cycle units. Each of the existing Sanford units to be converted produced approximately 400 MW of electricity at a heat rate of about 10,000 BTU/kWh. Following conversion, each unit will be capable of roughly 957

MW (summer) at a net heat rate of 6,860 BTU/kWh. The total cost of this conversion of both units is currently projected to be approximately $697,000,000. Cost estimates for the repowering projects may change slightly during construction.

I have included summary sheets for all of the above projects, as Document SSW-16.

Q. Were the Ft. Myers and Sanford repowering projects needed to maintain system reliability?

A. Yes. In 1997 FPL conducted reliability analyses that showed a need for new resources. Prior to that year, as previously discussed, FPL utilized a 15% summer peak reserve margin criterion in addition to use of 0.1 days/year LOLP. At that time there was increasing concern over reserves available during extreme winter peak conditions and whether use of a summer reserve criterion would be adequate. In the 1997 planning cycle, FPL addressed this concern by establishing a third reliability criterion: a 15% winter peak reserve margin.

The addition of a winter peak reserve margin criterion resulted in a need for new capacity in 2002. To demonstrate the need for new capacity, I have recreated a reserve margin analysis using data from FPL's 1998 Ten Year Site Plan, Schedule 7.2, which shows winter peak reserve margins for a ten year forecast period through the winter of 2006/2007. I have extracted the values for firm peak lead, total firm imports, total QF capacity from the winter of 2001/2002 and the total installed capability in existence prior to 2002. I have assumed no new capacity additions throughout the 2002 to 2007 time frame. This analysis is presented in Document SSW-17.

The analysis shows that by the winter of 2001/2002, interpreted as December 2001 through February of 2002, FPL has a need for an additional 355 MW of new resources to maintain a 15% reserve margin. By the winter of 2003/2004, the cumulative need has grown to 1,096 MW. Also, from the 1998 Ten Year Site Plan, the Ft. Myers repowering project was projected to add 1,062 MW of capacity (winter), which addressed the 2002 through 2003 need. The need for additional MW in 2003/2004 winter was to be addressed by the Sanford repowering. The 1998 Ten Year Site Plan showed in-service dates of 2002 for the Ft. Myers repowering project and 2004 for the Sanford repowering project, as the analysis would suggest.

Q. Were the decisions to undertake the Ft. Myers and Sanford repowering projects reasonable and prudent?

A. Yes. FPL evaluated the economics of the repowering against its own self-build options, primarily new combined cycle units. First, let me address the Ft. Myers repowering option and describe the project.

Prior to repowering, the Ft. Myers site consisted of two oil fired steam generating units summer rated 147 MW (unit 1) and 397 MW (Unit 2), plus a bank of 12 oil-fired combustion turbines rated at 626 MW total (summer). Repowering consists of replacing the oil-fired boilers at units 1 and 2 with 6 advanced natural gas fired combustion turbines and 6 heat recovery steam generators (HRSGs). At that time the repowering was envisioned to add 837 MW of incremental summer capacity. This repowering not only adds the incremental capacity, it also eliminates the oil consumption of the existing fossil-steam units with the associated environmental benefits, and improves the overall efficiency of those units by converting to a combined cycle operation. This improved efficiency is measured by a reduction in net heat rate from roughly 10,000 BTU/KWH to an original projection of 6,815 BTU/kWh. The installed construction cost of the project was forecast to be $593 per incremental kW, based on incremental summer kW, or a total of $496,000,000. The existing 544 MW of oil-fired capacity could be considered to be converted to combined cycle operation at no additional cost. Note that using current estimates of cost and capacity results in an installed cost of $545/kW.

Q. Please address the economics of the Ft. Myers repowering.

A. I will show the relative economics of the Ft. Myers repowering in two different ways. First, when the levelized costs of the repowering is compared over a range of capacity factors to the levelized costs of the FPL self-build options, it is clear that repowering offers lower costs. This comparison is shown in my Document SSW-18. Known as screening curves, the comparison in this exhibit is often used to sort relatively similar options. In this case repowering was compared to a range of combined cycle alternatives using several generations of advanced combustion turbine technology, including some units not projected to be available until after the date new capacity was needed. The comparison also was made to simple cycle combustion turbines and circulating fluidized bed (CFB) coal technology.

A second, more comprehensive, examination of the relative economics was done using the Electric Generation Expansion Analysis System (EGEAS), which is an optimization program capable of simulating system production costs and calculating the revenue requirements associated with the addition of new generation. Document SSW-19 shows the results of a dynamic optimization, comparing the two most economic plans. This comparison shows that repowering Ft. Myers 1 and 2 saved approximately $166 million, NPV, versus construction of new combined cycle units.

Q. Were there other savings from the repowering of the Ft. Myers units?

A. Yes. Referring to FPL's 1998 Ten Year Site Plan:

> ….FPL's system transmission reliability analyses showed that either new transmission capacity or approximately 400 MW of new generation capacity was needed in Southwest Florida by January, 2002, to alleviate potential electrical reliability problems which could occur in the area during winter peak loads.

(page 38).

Repowering of Ft. Myers added sufficient capacity to avoid construction of a new 500-kV line across the State. At that time the capital cost of the new line was estimated to be roughly $80 million. The cost savings associated with avoiding this line are not included in the earlier $166 million savings figure.

Q. **Did FPL compare repowering to other proposals through an RFP?**

A. No. Since the repowering project did not require licensing under the Power Plant Siting Act (PPSA), it did not fall under the Commission rule requiring an RFP. However, beyond the issue of whether or not an RFP is required, there was the practical consideration of seeking alternatives to an option that was already considerably lower cost than a new construction project. The advantages inherent in these initial repowerings, (i.e. converting existing less efficient oil-fired capacity to natural gas-fired combined cycle capacity) cannot be duplicated by constructing new capacity elsewhere. Barring site-specific impediments, the decision to repower was essentially a "no brainer."

Q. **Has FPL made any attempt to ensure that the repowering project is cost effective versus new combined cycles built by others?**

A. Yes. A review of new combined cycle costs presented in published sources, which I have attached as Document SSW-20, shows that at its 1998 estimate of $593/kW (1998 FPL Ten Year Site Plan) in 2002, the repowering is very competitive with other new combined cycle units built in the state in earlier years, including FPL's Martin project ($513/kW, 1994), Lauderdale repowering ($549/kW, 1994), FPC's Hines unit ($543/kW, 1999) and Hardee Power Partners Hardee Unit ($618/kW, 1993). Given the escalation that would be expected in these prices to 2002 and the system fuel savings that repowering generates by converting existing steam generation to combined cycle generation, the Ft. Myers repowering would be expected to be very economic, even without consideration of the additional savings resulting from avoidance of trans-state transmission.

Q. Are there other reasons why repowering of Ft. Myers was the best alternative for FPL expansion?

A. Yes. In addition to the transmission savings I have already discussed, by replacing the oil fired units at Ft. Myers with natural gas fired combined cycle units, emissions were substantially reduced, even when compared to construction of new combined cycle units, and barge traffic to the site was essentially eliminated. The reduction in emissions versus new units comes from the conversion of existing capacity to combined cycle operation.

Q. Please discuss the economics of the Sanford repowering.

A. I have already shown that additional MW were needed beyond the Ft. Myers repowering to maintain reliability in subsequent years. FPL examined repowering of its Sanford units versus the addition of new combined cycle units. This repowering project evolved over time to its current scope, but initially, the proposed repowering was to convert Sanford Unit 3 (153 MW) and Unit 4 (383 MW) to combined cycle operation in a project essentially identical to that at Ft. Myers. Both units were also oil-fired steam generation with heat rates approximating 10,000 BTU/kWh. Based on the similarity to Ft. Myers, the relative economics were expected to be the same. Again using EGEAS to determine overall savings, Sanford Units 3 and 4 repowering saved \$18 million, NPV, versus construction of new combined cycle units as shown in Document SSW-21.

This modest economic margin led to a reexamination of the proposed project. Beyond the economics, the proposed repowering of Sanford units 3 and 4 left one unconverted 400 MW class oil-fired unit at the Sanford site. To improve the site environmental profile, and in an attempt to lower the \$/kW cost of the project, efforts were refocused leaving only the smallest unit, Unit 3, as an oil-fired unit. This change in direction lowered construction costs by \$15/kW and reduced non-fuel O&M expense, while leaving fuel costs at the unit essentially unchanged. It also increased system fuel savings. The decision was made to repower Units 4 and 5 in 1997, and the project will be completed in 2002. Repowering of Sanford units 4 and 5 will add approximately 1,134 MW of capacity (summer) to FPL's system.

Q. Has FPL reassessed the cost-effectiveness of the Ft. Myers and Sanford repowerings to ensure that continuing the project is reasonable and prudent?

A. Yes. In Document SSW-22, I show the results of an economic analysis of both the Ft. Myers and Sanford repowering projects. The analysis shows that Sanford saves approximately \$14 million, NPV, versus new combined cycle units, while the Ft. Myers repowering saves approximately $140 million, NPV, without consideration of the transmission benefit I discussed earlier. The analysis used the most current cost estimates of both projects at completion, which I presented earlier.

Q. Does FPL favor repowering of existing units even if economics are relatively the same as new construction?

A. Yes. If the economics are essentially the same, the repowering of older, less efficient units has obvious environmental advantages, as well as the advantage of significantly improving the overall efficiency of FPL's fleet.

The environmental advantages include use of existing land and water resources, resources which are already designated for power plant use, and, as I discussed with regard to Ft. Myers, an improved air emissions profile when compared to construction of a new combined cycle unit.

This latter effect comes from complete conversion of existing MW rather than simple operational displacement of those same MW. Consider a comparison of adding 1,100 MW by repowering Sanford, versus adding 1,100 MW of new combined cycle capacity. Prior to repowering, Sanford Units 4 and 5 represent about 770 MW of oil and gas-fired steam capacity. If I add 1,100 MW of combined cycle capacity to meet incremental load, the Sanford units will continue to run in their pre-repowered mode. They will run fewer hours, but certainly more than zero, and they will probably burn oil as most of the system gas will be dedicated to the more efficient combined cycle units.

If, however, I repower the units, that existing 770 MW runs in a highly efficient combined cycle mode, along with the new 1,100 MW. The entire configuration produces more kWh per BTU of fuel than the new combined cycle/old Sanford configuration, and produces lower air emissions.

Q. Did FPL issue an RFP to identify alternatives to the Sanford project?

A. No. For the same reasons I discussed with regard to Ft. Myers, no RFP was issued when the decision to repower Sanford was made. Referring again to FPL's 1998 Ten Year Site Plan:

> The Sanford project is very similar in scope to that planned for Ft. Myers and is expected to be similar in regard to its economic attractiveness. (page 39).

Economics, as well as the previously discussed environmental advantages, made the Sanford repowering an obvious choice.

Q. Has FPL pursued all of the cost-effective DSM it can in an effort to defer or avoid the need for the Ft. Myers and Sanford repowering projects?

A. Yes. This is evidenced by FPL's filing of its DSM plan with the Commission in 1999 (Docket No. 991788-EG Approval of Demand-Side Management Plan of Florida Power and Light Company) and approval by the Commission of this plan (Order No. PSC-00-0915-PAA-EG, May 8, 2000). This was, of course, an approval of the specific programs to be implemented by FPL to meet overall numeric DSM goals approved by the Commission in a prior proceeding (Docket No. 971004-EG, Order No. PSC-99-1942-FOF-EG). This latter order set goals for FPL of 169.4 MW of residential summer peak reduction and 99.6 MW of commercial/industrial summer peak reduction by 2002.

Q. Do these goals establish the cost-effective levels of DSM that are reasonably achievable?

A. Yes. The purpose of the DSM Goals proceeding was to establish the reasonably achievable DSM levels over a ten year period. FPL is also required to file new goals every five years.

Given that the goals were approved in 1999, subsequent to FPL's identification of a need for capacity in 2002, and the fact that the need remained after approval of those DSM goals, it is fair to say that the Ft. Myers and Sanford projects could not be deferred or avoided by additional cost effective DSM.

Q. Please summarize the need for the Ft. Myers and Sanford repowering projects.

A. Both projects were needed to meet system reserve margin requirements, Ft. Myers in 2002, and Sanford was originally projected to be needed in 2004. Subsequent to the studies performed in 1997 which demonstrated those needs, FPL agreed to employ a 20% reserve margin criterion for planning purposes and set about to implement it quickly. These changes along with upward shifts in the load forecast moved the need for the Sanford project to 2002, where it is currently projected to be in-service. Fortunately, the flexibility afforded by repowering allowed FPL to make this change.

The repowering projects were, and continue to be, the most reasonable and prudent means of meeting the need identified by FPL. There is not sufficient cost-effective DSM available to defer or avoid the need for these projects. These capacity additions therefore best meet FPL's overall planning objectives.

Q. Will the Ft. Myers and Sanford repowered units be used and useful?

A. Yes. I expect the repowered units at both sites to run at a high capacity factor and contribute substantially to lowering FPL's system fuel costs.

<u>FPL's Sales Forecast</u>

Q. What is FPL's process to forecast the level of energy sales?

A. The forecast of the level of energy sales consists of three steps. First, total Net Energy for Load output is projected; next, a line loss factor is applied to this output to arrive at a total customer end-use energy demand of electricity. Finally, revenue class models are developed to distribute the total end-use sales of electricity forecast to the different revenue classes such as residential, commercial, industrial, etc. FPL's process and models for forecasting energy sales are discussed in detail in MFR Schedule F-9, pp 1-3, and Attachments 2-5 of MFR Schedule F-9.

FPL develops econometric models to explain and predict the level of energy sales. Explanatory factors, such as the weather, the price of electricity, the economic conditions in Florida, the number of customers and seasonal factors are used to develop the forecast of energy sales. An econometric model is a numerical representation, obtained through statistical estimation techniques, of the degree of relationship between the level of energy sales and the explanatory factors. A change in any of the explanatory factors will result in a corresponding change in the level of energy sales. On a historical basis, econometric models have been proven to be highly effective in explaining changes in the level of energy sales.

Predicting what the level of sales is going to be in a future year requires first an assumption regarding the levels of the explanatory factors. These assumptions are obtained from different sources. For example, the future number of customers will depend on population projections produced by the University of Florida's Bureau of Economic and Business Research (BEBR). The projected economic conditions are secured from reputable economic forecasting firms such as Standard and Poors' DRI-WEFA. The weather factors are obtained from the National Oceanographic and Atmospheric Administration (NOAA). The price of electricity is produced internally by FPL and is a result of the Commission's approved base rates and fuel factor clauses. Seasonal factors in the consumption of electricity come from two sources, the weather seasons and the population seasonal pattern. Substantial analysis is performed in order to ensure that the assumptions regarding the explanatory variables are reasonable. This ensures that the forecast of energy sales is both realistic and rational.

The final end-use energy demand of electricity or billed energy sales is NEL adjusted for line losses and billing cycle tuning for the difference between when a customer consumes electricity and when the meter is read. Due to this accounting practice, a superior econometric forecasting model is obtained if NEL, instead of billed energy sales, is matched to the explanatory factors. This is because the NEL data do not have to be attuned to account for billing cycle adjustments, which might distort the real time match between the production and consumption of electricity.

To project energy sales by revenue class, separate models for the residential, commercial, and industrial revenue classes are developed. The sum of all revenue classes will result in total energy sales, which is adjusted to coincide with the total energy sales derived from the NEL model. These revenue class models are developed to obtain an objective allocation of the total energy sales between its different revenue classes.

Q. What are the primary inputs to determine the growth in energy sales?

A. The growth in usage of electricity comes from the overall growth in per capita use of electricity by all customers and the growth in the number of new customers. The product of per capita usage times the number of customers yields the NEL for a given period. Both the per capita usage of electricity and the growth of new customers are linked directly to the performance of the local and national economy. When the economy is booming, usage of electricity is up in all sectors: residential, commercial, industrial and others. Furthermore, if the economy is strong there will be new jobs that attract new customers, new households develop, and retirees coming from other states increase in numbers. The reverse also holds, if the economy is performing poorly, customers are more apprehensive as to how their reduced income is spent, restricting their level of consumption of goods and services. Electricity demand and sales begin to slacken when income falls. Job contractions reduce the number of new customers coming to the state seeking employment opportunities. New household formations are postponed.

FPL relies on the outlook for the local and national economy produced by Standard and Poors' DRI-WEFA and the population growth forecast developed by the University of Florida.

Q. What were the basic assumptions included in the original MFR forecast?

A. The original energy sales forecast was produced in the summer of 2001. At that time DRI-WEFA's outlook was that the national economy would experience only a modest slowdown in 2001 and then rebound with good economic growth in 2002. The economy of the State of Florida was forecast to again outperform the rest of the nation in 2001 and 2002. Consequently, Florida's population forecast also reflected the then recent trend of strong growth in new residents associated with outstanding job creation in the state. For example, job growth in Florida was projected to grow by 1.6% in 2001. By July of 2001, job creation was growing at the rate of 2.7% and Florida boasted of having created 250,000 new jobs while the US economy on the whole had created only 750,000 new jobs. One out of every three new jobs in the United States was created in Florida. New housing starts were up by 12.6% over 2000, a banner year, and real per capita income was soaring above the projected 2.2 %. Customer growth was comparable to the growth obtained in 2000, the highest in the last 10 years. The preliminary indicators suggested a continuation of optimistic economic conditions.

With this basis, FPL's energy sales were projected to grow at the rate of 3.9% in 2001 and 3.5% in 2002. Customer growth was estimated to reach 87,000 in 2001 and 86,000 in 2002. The resulting usage per customer growth was estimated at 1.6% in 2001 and 1.3% in 2002. These energy and customer growth parameters are all above the average of the last five years, a period characterized by outstanding economic performance, low prices of electricity and hotter than normal weather conditions.

FPL projections did not anticipate the events of September 11, 2001 and the resulting economic aftermath. This event has made the original forecast inappropriate for rate making or any other planning process.

Q. Why did FPL update the energy sales forecast?

A. The change in Florida's economic look for 2001 and 2002 brought on by the events of September 11, 2001 warrants a revision to FPL's sales forecast. In its U.S. Economic Review of October 2001, which FPL relied upon to revise its energy sales forecast, DRI-WEFA pronounced, "It no longer seems possible for the U.S. economy to escape a recession...the question of whether the U.S. economy escapes a recession appears to have been settled by the September 11 terrorist attacks." DRI-WEFA then expected the third and fourth quarters of 2001 to register declines in Gross Domestic Product (GDP), a measure of total domestic output, and they projected only a 1% real overall growth for the entire year. Their forecast of a decline in third quarter GDP was proved correct with the announcement of a 1.3% decline for the quarter. Their October outlook for year 2002 had the economy growing at a real rate of 1.3%, starting out weakly and then picking up strength in the latter part of the year in response primarily to federal programs stimulus. Prior to September 11, 2001 the forecasted real growth in GDP for 2001 was 1.6% and 2.6% for 2002.

Q. What is the impact of the changed economic outlook on FPL's projected electricity sales?

A. Document SSW-23, shows FPL's revisions in the level of projected sales and customers for 2001 and 2002. FPL produced a new outlook for energy sales by changing the economic assumptions utilized in its forecasting models. FPL made use of the then most recent economic outlook for the State of Florida produced by DRI-WEFA that incorporated the revision resulting from the events of September 11. I should note here that the DRI-WEFA forecast was the most optimistic of the revised forecasts at that time. The new projected use of electricity per customer for 2002 is slightly higher than the estimated 2001 value, but it is 2.5% lower than the forecast produced with economic assumptions prior to September 11. So even with DRI-WEFA's lower economic outlook, the resulting customer usage in 2002 is slightly higher than 2001, which appears conservative given the actual declines in usage experienced in prior recessions.

Customer growth outlook has changed from 85,643 to 65,000 new customers in 2002. The recession outlook has resulted in a reduction in forecasted growth of approximately 20,000 less new customers in 2002. In order to forecast customer growth, FPL models depend on population projections obtained from the Bureau of Economic and Business Research of the University of Florida (BEBR). However, BEBR has not updated the population projections as a result of the terrorist attacks of September 11. Therefore, FPL's projection of customer growth is based upon growth in customers during prior recessions.

The decline in the growth of the number of customers from the year prior to a recession to the year following a recession can be seen in Document SSW-24. In the recessions since 1972, FPL has seen a significant decline in the growth of customers from the year prior to the recession to the year following the recession. In the 1974/75 recession, FPL experienced a decline in the growth of customers of almost 64,000 (1973 versus 1976). In the 1982 recession, FPL experienced a decline in the growth of customers of roughly 29,000 (1981 versus 1983). In the 1990/91/92 recession, FPL experienced a decline in the growth of customers of approximately 36,000 (1989 versus 1993). A simple average of the decline in growth from those prior recessions would suggests that FPL might anticipate a reduction in the growth of customers due to recession of 43,000. However, two of those recessions were longer term, and this recession is forecast by DRI-WEFA to be relatively shorter. In addition, assuming a customer growth reduction of 43,000 would have reduced FPL's customer growth to 49,000, a lower level than FPL has experienced in any year since 1972, including the low year of growth in 1992 following Hurricane Andrew. So, it was considered prudent to take a more conservative approach. FPL projected that it would lose approximately 27,000 customers from the year prior to the recession (2000) to the year following the recession (2002). This is close to but lower than the decline in customer growth experienced during the 1982 recession, and it leaves 2002 customer growth at 65,000 customers, which is about the average new customer growth seen for most of the decade of the 1990s.

The combination of the revised use per customer multiplied by the new projection of customers results in a projected level of sales of 100,158 GWh in 2002, a 1.7% growth over 2001, as shown in Document SSW-23.

Q. Are there compelling reasons to believe this revised forecast is too optimistic?

A. Yes. Even the revised forecast is likely to be optimistic. There are persuasive reasons that dispute the predicted level of sales, suggesting it could be lower.

First, we used the most optimistic forecast of economic conditions (DRI-WEFA). Other forecasters, specifically Blue Chip and Manufacturer's suggested deeper drops and a longer recession. In addition, the more recently issued DRI-WEFA forecast (December) now paints a more pessimistic picture.

Second, the national economic outlook assumes that the recession will be short lived, with significant economic growth by the third quarter of next year. However, for Florida, the terrorist attacks of September 11, 2001 strike at the heart of the state's economy. Florida's economy has become more vulnerable because the most impacted industries are relatively more vital to the Florida economy than most other states. These heavily impacted industries are tourism, air travel, merchandise trade, airline services, and the cruise industry. Of course, the downturn in these industries will have spillover employment and income effects on the rest of sectors that encompass the Florida economy.

The combined effects of the slowing US economy and the perceived risks of air travel will adversely affect Florida's economy in comparison to the national economy. DRI-WEFA expects international visitation to Florida and domestic travel to be lower as a result of the weakening global economy, security fears, and concern about employment security and declining income.

Third, Document SSW-24, shows the effect of the last three national recessions on Florida's Real Per Capita Income, the customer growth in FPL's service territory, and the changes in electricity use per customer. The three prior recessions which affected Florida, 1974-1975, 1982, and 1990-1992, resulted in negative growth for both Florida's Real Per Capita Income and electricity use per customer in FPL's service territory. In FPL's revised forecast, Florida's Real Per Capita Income is projected to experience a positive 1.3% growth and usage per customer is also projected to increase slightly. DRI-WEFA has now revised their growth estimate down to –1.16% for 2002.

Fourth, in prior recessions, customer growth between the year prior to the recession and the year after the recession dropped by an average of 43,000 new customers. This forecast assumes that the reduction in customer growth between the year prior to the recession compared to the year after the recession to be only 20,642 new customers.

Fifth, it has been observed historically that the three largest counties in FPL's service territory have experienced a larger impact from economic slowdowns relative to other major counties in the state. For example, in past recessions unemployment rates have been higher in Miami-Dade, Broward and Palm Beach Counties compared to Duval, Hillsborough and Pinellas Counties, as shown in Document SSW-25. In addition, per capita income, another key economic indicator, has also declined significantly during recessions in the counties served by FPL relative to other Florida counties as shown in Document SSW-26. Therefore, it is highly likely that this recent slowdown will have a greater impact on FPL's service territory relative to non-FPL service areas, yet the October DRI-WEFA economic outlook obtained and utilized in this forecast is for the entire State of Florida.

Sixth, the observed level of energy sales since September has fallen by a larger magnitude than expected when the forecast was revised. Document SSW-23, shows that the NEL forecast revision for 2002 included a revision to the sales for 2001 from a projected 3.9% growth to 3.3%. The actual NEL growth was .7% below the revised forecast. That error is wholly attributable to the last four months of 2001.

Q. Is FPL's revised forecasted energy usage in 2002 reasonable?

A. A forecast is considered reasonable if good judgement is utilized in estimating and testing the model (availing oneself of the appropriate and most credible assumptions on hand) and if the results or outputs make sense when compared to prior similar situations. FPL followed this approach in preparing the revised forecast due to the events of September 11, 2001.

The models employed by FPL have good descriptive statistics with a high degree of statistical significance. FPL is confident that the relationship that exists between the level of energy sales and the economy, weather, customers and price of electricity, etc. has been properly assessed and numerically quantified.

FPL was thorough and comprehensive in securing the best data available to assess the impact of the events of September 11, 2001 and its aftermath. FPL relied on several sources of data and utilized the most conservative ones. Therefore, at the time it was performed, FPL's revised forecast was reasonable.

Q. **Have subsequent data led you to believe that FPL's revised sales forecast may overstate FPL's revenues?**

A. Yes. Further analysis examining the behavior of customer growth and the rate of real per capita income in years following recessions suggests the revised forecast is optimistic. This is borne out by FPL's actual experience since its forecast was revised, with customer growth showing a significant decline in the fourth quarter of 2001. Also, DRI-WEFA's December forecast, which still forecasts a relatively mild and short-lived recession, now shows negative per capita income growth rate for the entire year.

Q. Will the economic effects caused by September 11, 2001 impact FPL's sales forecast beyond 2002?

A. Yes. The economic reaction to the events of September 11, 2001 is a known event affecting FPL's sales in 2002 and beyond that cannot be ignored. The going forward effect of the economic impact of the September 11 events have been incorporated into FPL's updated sales forecast, which covers not only 2002, but 2003 through 2006 as well. Sales in all the forecast years 2002 through 2006 have been impacted by the events in two ways.

The first, most obvious impact is that sales in the short-term are reduced, and these "lost" sales will never be fully recovered. Put another way, "lost" sales result in a lower base for future years' growth and thus effect a permanent downward shift of the growth curve in future sales.

Second, there have been some permanent changes in both the national and Florida economies as a result of the September 11 events. Some businesses have failed, permanently removing them from the economy. Other businesses have had dramatic reductions in activity that will not be recaptured in one or two years. For instance, airline travel, and related businesses, have suffered long-term impacts from the public's increased fear of flying and the increased security restrictions that make flying more difficult. Simply stated, there are short and long-term economic impacts from the September 11 events. FPL has attempted to capture those impacts in its revised forecast of sales from

2002 through 2006 by utilizing the DRI-WEFA revised economic forecast. However, FPL is concerned that these economic impacts have not been fully captured and that the revised forecast overstates FPL's projected revenues for 2002 as well as the remaining years of the forecast.

Q. Would you please summarize your testimony?

A. In the course of my testimony, I have:

- Described FPL's planning objective and the process employed by FPL to maintain system reliability at a reasonable cost;

- Described the improvements to FPL's fleet of power plants and shown that these improvements have resulted in considerable savings to FPL's customers;

- Discussed the fact that, overall, FPL's production O&M expense forecast for 2002 is not only within the Commission's O&M benchmark, but also $44.6 million lower than the level the Commission approved for 1988;

- Addressed FPL's superior power plant performance while at the same time reducing Production O&M costs and explained why this exemplary performance justifies an ROE adder;

- Justified the variance above the benchmark in Production-Other by both the movement of repowered units from the Production-Steam function and the addition of new generating units;
- Described power plant additions to FPL's system since its last rate case and demonstrated that these additions are reasonable and prudent and used and useful in serving FPL's customers;

- Discussed the new generating units that will be added to FPL's system during 2002, and shown that they were the reasonable and prudent additions, will provide important non-economic benefits, and will be used and useful in serving FPL's customers; and

- Presented FPL's energy forecast, including a discussion of the methodology as well as the changes to the forecast resulting from the events of September 11, 2001.

Q. Does this conclude your testimony?

A. Yes it does.

MFRS SPONSORED OR CO-SPONSORED BY SAMUEL S. WATERS

MFRs Sponsored:

B-17a	System Fuel Inventory
B-17b	Fuel Inventory by Plant
B-18	Capacity Factors
E-26	Monthly Peaks
F-8	NRC Safety Citations
F-10	Forecast Model Sensitivity
F-11	Forecast Model Historical Data
F-12	Heating Degree Days
F-13	Cooling Degree Days
F-14	Temperature at Time of Monthly Peaks

MFRs Co-Sponsored:		Co-Sponsor:
A-7	Statistical Information	Davis
A-8	15 Year Analysis-Change in Costs	Davis/Olivera/Hamilton
B-10	Capital Additions and Retirements	Davis/Olivera/Peterson
B-12a	Future Use Property – 13 Month Avg.	Davis/Olivera/Peterson
B-13b	CWIP – Other Details	Davis/Olivera/Peterson
B-16	Nuclear Fuel Balances	Davis
B-20	Plant Materials & Operating Supplies	Davis/Olivera/Peterson
B-27	Detail Changes in Rate Base	Davis/Olivera/Peterson
B-30	Net Production Plant Additions	Davis
C-8	Report of Operation vs. Forecast	Davis/Olivera/Hamilton/Peterson
C-12	Budget vs. Actual-Revenues/Expenses	Davis/Olivera/Hamilton/Peterson
C-14	Monthly Fuel Expenses	Davis
C-15	Fuel Revenues & Expenses Reconciliation	Davis
C-19	O & M Expenses – Test Year	Davis/Olivera/Hamilton
C-20	O & M Expenses – Prior Year	Davis/Olivera/Hamilton
C-21	Detail Changes in Expenses	Davis/Olivera/Dewhurst
C-27	Industry Association Dues	Davis/Olivera/Hamilton
C-57	O & M Benchmark Variance by Function	Davis/Hamilton
C-59	Attrition Allowance	Davis
C-65	Outside Professional Services	Davis/Olivera/Hamilton/Peterson
E-12	Cost of Service Study – Load Data	Morley
E-14	Development of Demands for Loss Study	Morley
E-18a	Billing Determinations – No. of Bills	Morley
E-18c	Billing Determinations – MWh Sales	Morley
E-28b	Curtailable Rates Policy	Morley
F-9	Forecasting Models	Davis
F-17	Assumptions	Davis/Dewhurst/Olivera/Peterson

**North American Electric Reliability Council (NERC)
Definitions for EFOR and EAF:**

EFOR for Total Unit $= \dfrac{\text{FOH + EFDH} \quad \text{X 100 \%}}{\text{SH + FOH + EFDHRS}}$

EAF for Total Unit $= \dfrac{\text{AH – (EUDH + EPDH + ESEDH)X 100\%}}{\text{PH}}$

FOH = Unplanned (Forced) Outage Hours

- Sum of all hours experienced during Full Forced Outages

EFDH = Equivalent Unplanned (Forced) Derated Hours

- Sum of all hours experienced during Partial Forced Outages converted into equivalent Full Forced Outage Hours
- Product of the Unplanned Derated Hours and the Size of MW Reduction, divided by the Net Maximum Continuous Capacity

SH = Service Hours

- Total number of hours a unit was electrically connected (full or partial) to the transmission system.

EFDHRS = Equivalent Unplanned (Forced) Derated Hours during Reserve Shutdowns Only

- Product of the Forced Derated Hours (during Reserve Shutdowns (RS) only) and the Size of MW Reduction, divided by the Net Maximum Continuous Capacity

AH = Available Hours

- Sum of all Service Hours, Reserve Shutdown Hours, Pumping Hours, and Synchronous Condensing Hours

EUDH = Equivalent Unplanned (Forced) Derated Hours

- Product of the Unplanned Derated Hours and the Size of MW Reduction, divided by the Net Maximum Continuous Capacity

EPDH = Equivalent Planned Derated Hours

- Product of the Planned Derated Hours (including Overhauls and Maintenance) and the Size of MW Reduction, divided by the Net Maximum Continuous Capacity

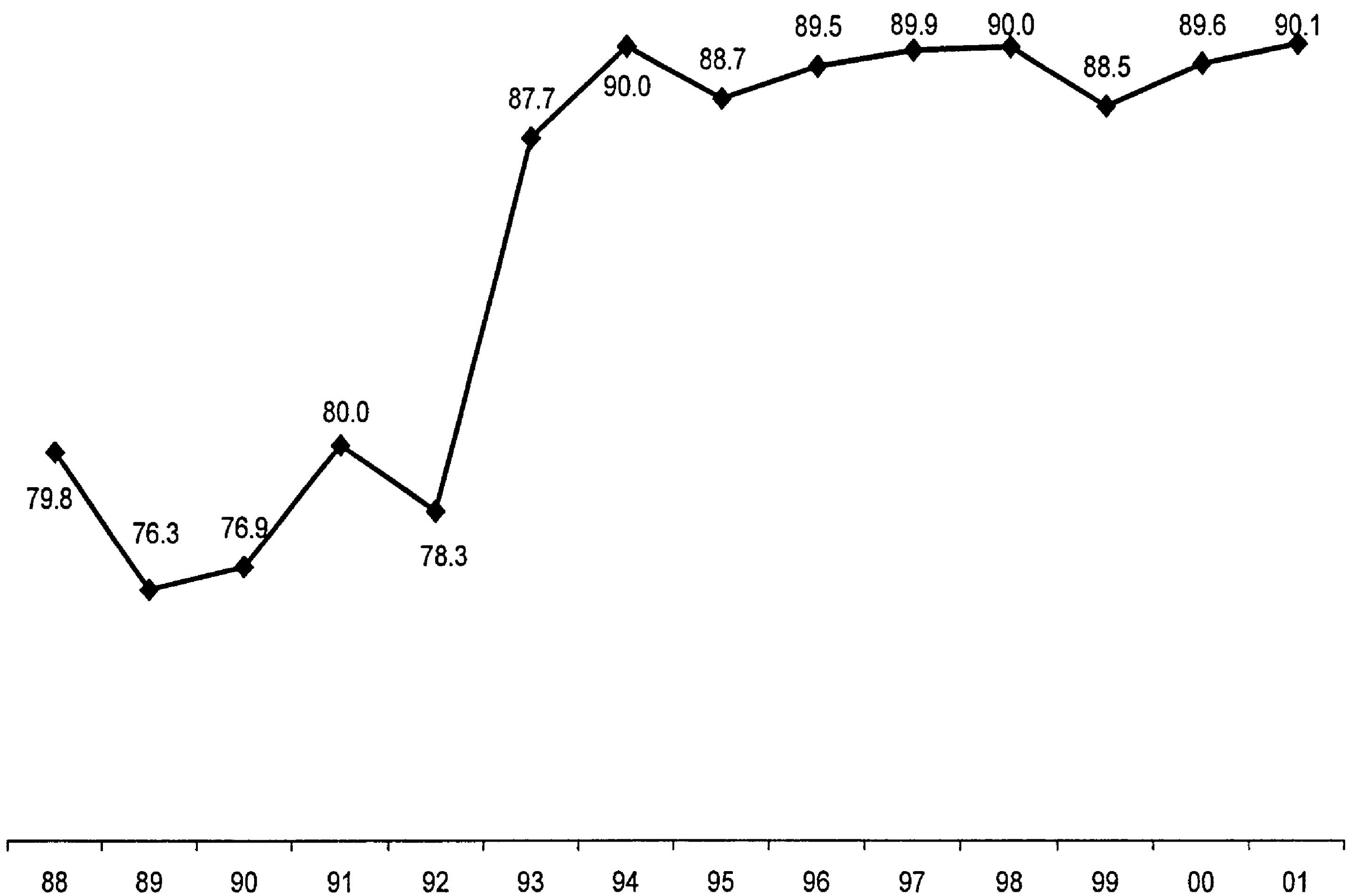
ESEDH = Equivalent Seasonal Derated Hours

- Sum of all partial derated hours due to ambient conditions converted into equivalent Full Unavailable Hours
- Net Maximum Capacity less the Net Dependable Capacity (Net Maximum Continuous Capacity modified for ambient conditions), times the Available Hours, divided by the Net Maximum Continuous Capacity

PH = PERIOD HOURS

- Number of hours a unit was in the active state (generally, all hours in a calendar period). A unit generally enters the active state on its commercial date.

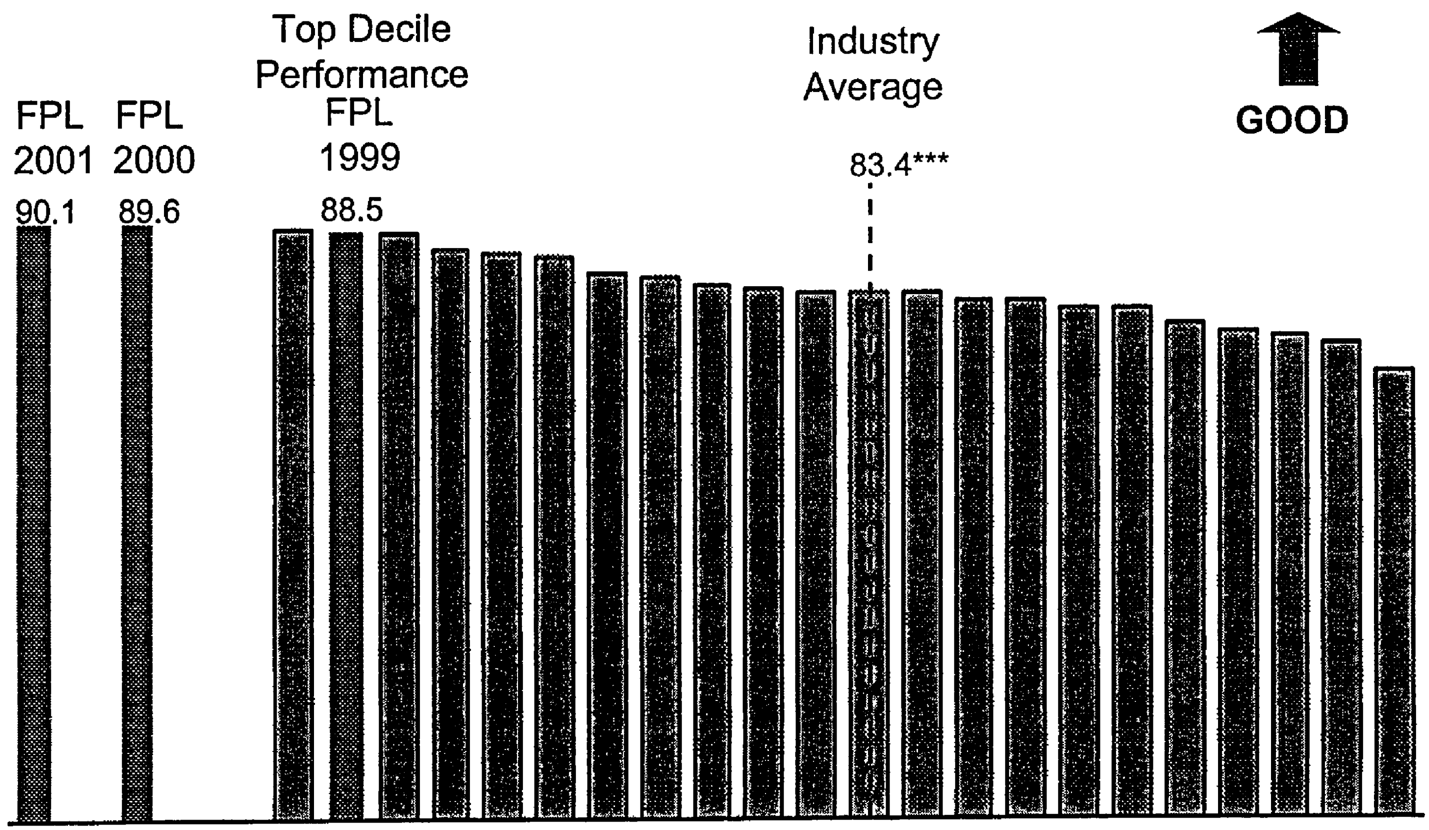
Equivalent Availability Factor*
(EAF %)
FPL Fossil Plants



Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-3, Page 1 of 1
Equivalent Availability Factor

* EAF here includes all components (MOF, FOF, POF) reported by FPL annually to NERC

FPL Vs. U.S. Largest Mw Capacity Fossil Utilities*
Equivalent Availability Factor (EAF %)**
1999



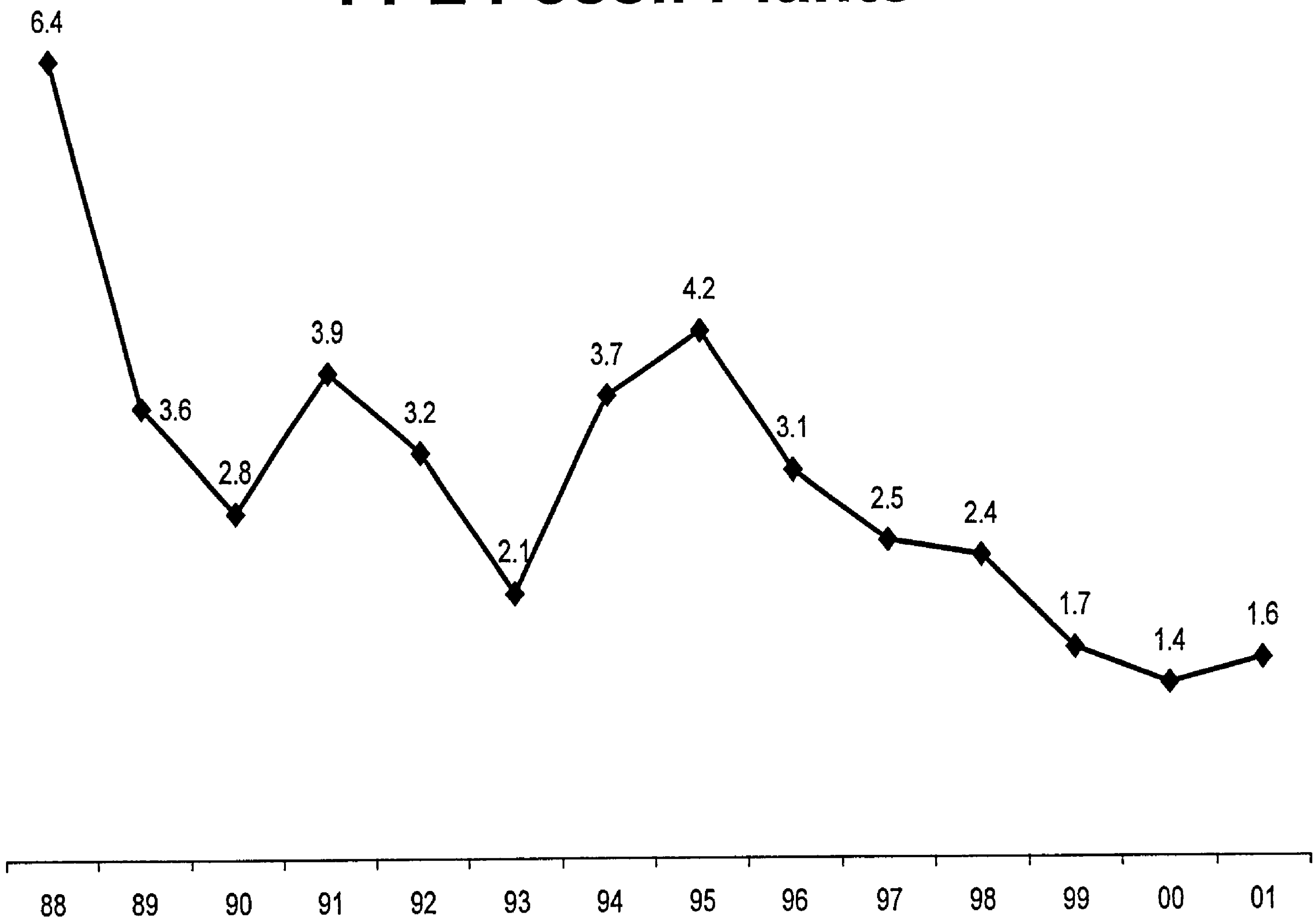
* Based on utilities with at least 5000MW capacity (22 utilities) in NERC database

** EAF here includes all components (MOF, FOF, POF) reported by FPL annually to NERC

***Average of all utilities in NERC database

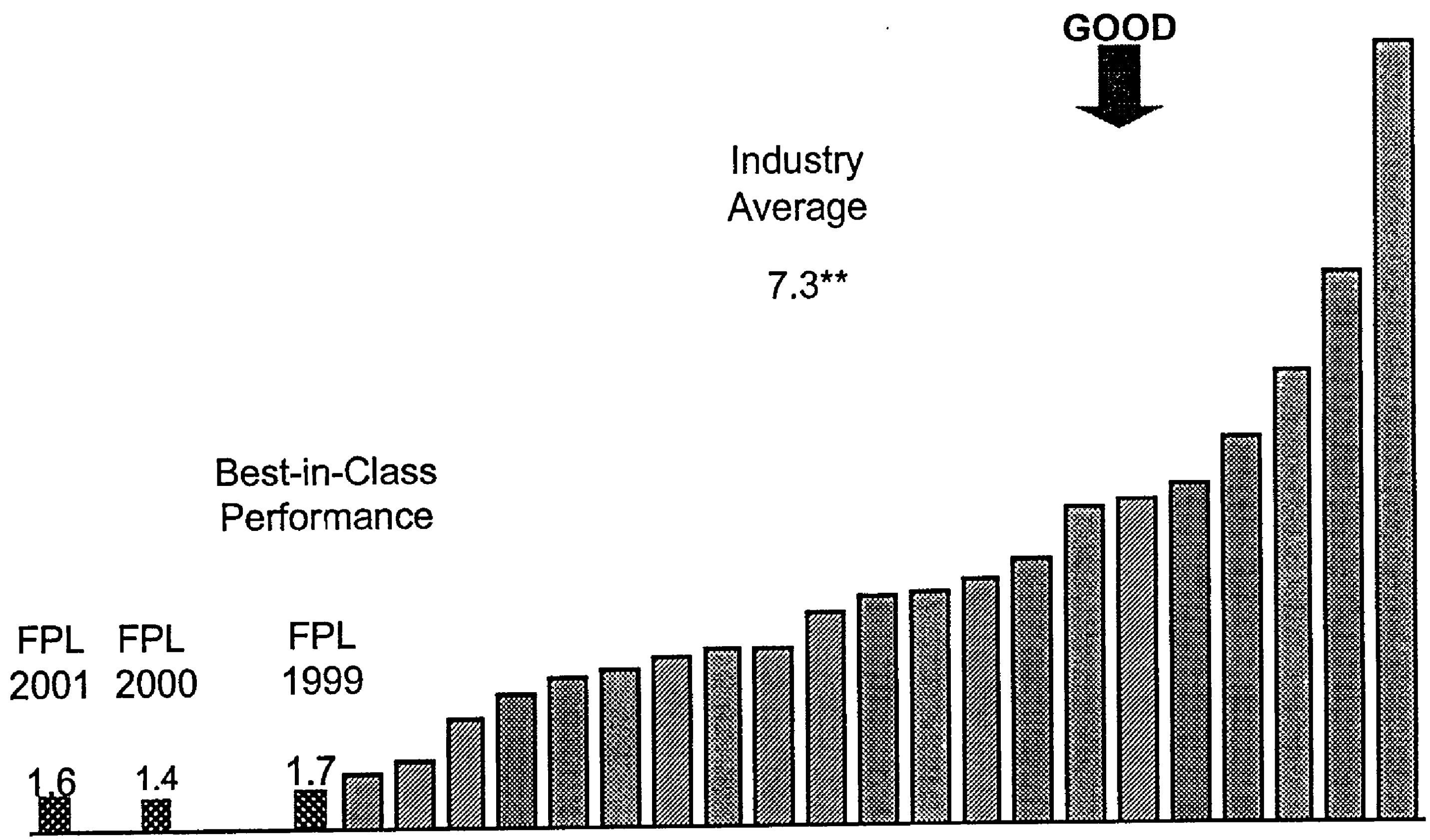
Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-4, Page 1 of 1
FPL Vs. U.S. Largest Mw Capacity

Equivalent Forced Outage Rate
(EFOR %)
FPL Fossil Plants



Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-5, Page 1 of 1
Equivalent Forced Outage Rate

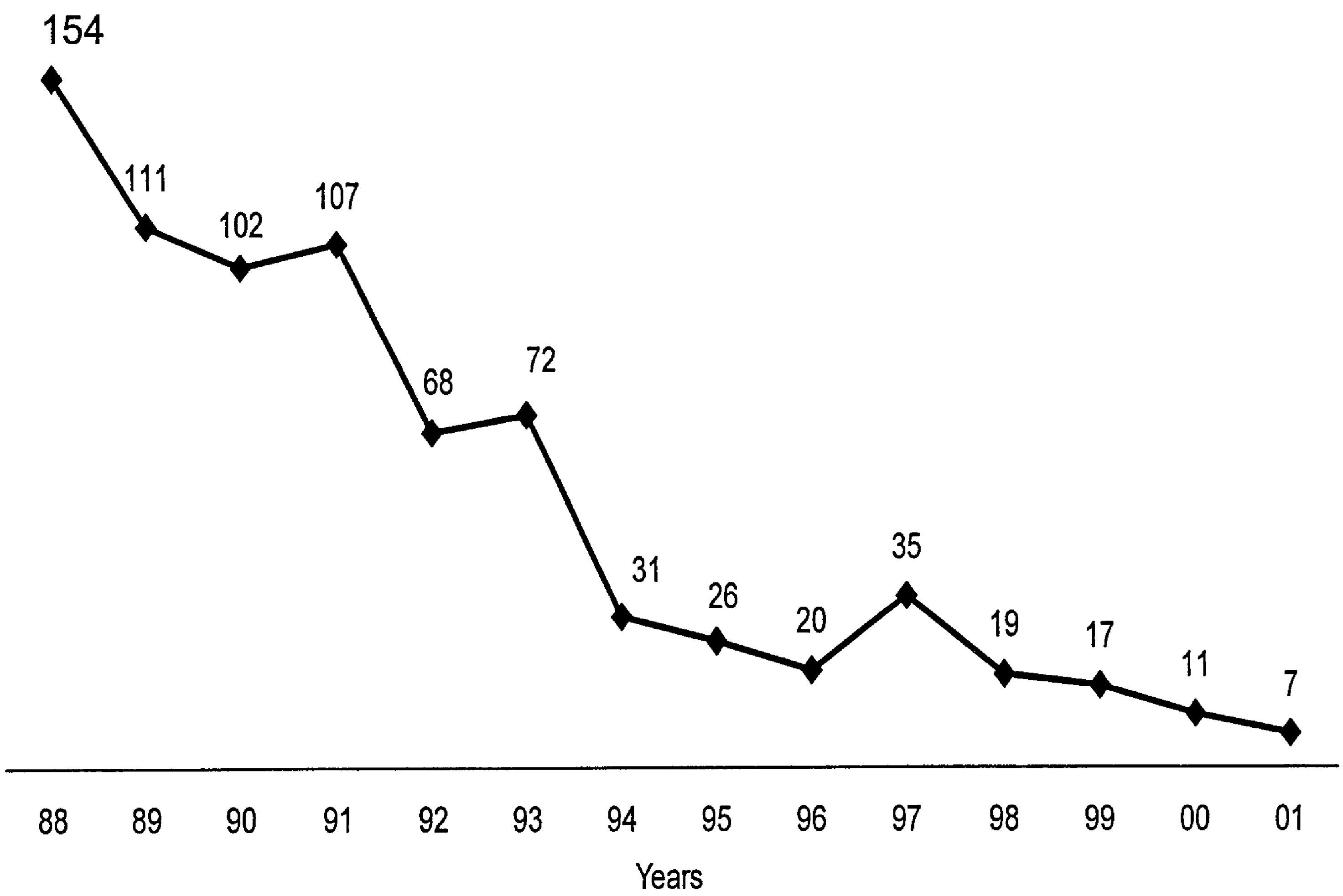
FPL Vs. U.S. Largest Mw Capacity Fossil Utilities*
Equivalent Forced Outage Rate (EFOR %)
1999



* Based on utilities with at least 5000MW capacity (22 utilities) in NERC database
** Average based on all utilities in NERC database

Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-6, Page 1 of 1
FPL Vs. U.S. Largest Mw Capacity
Fossil Utilities

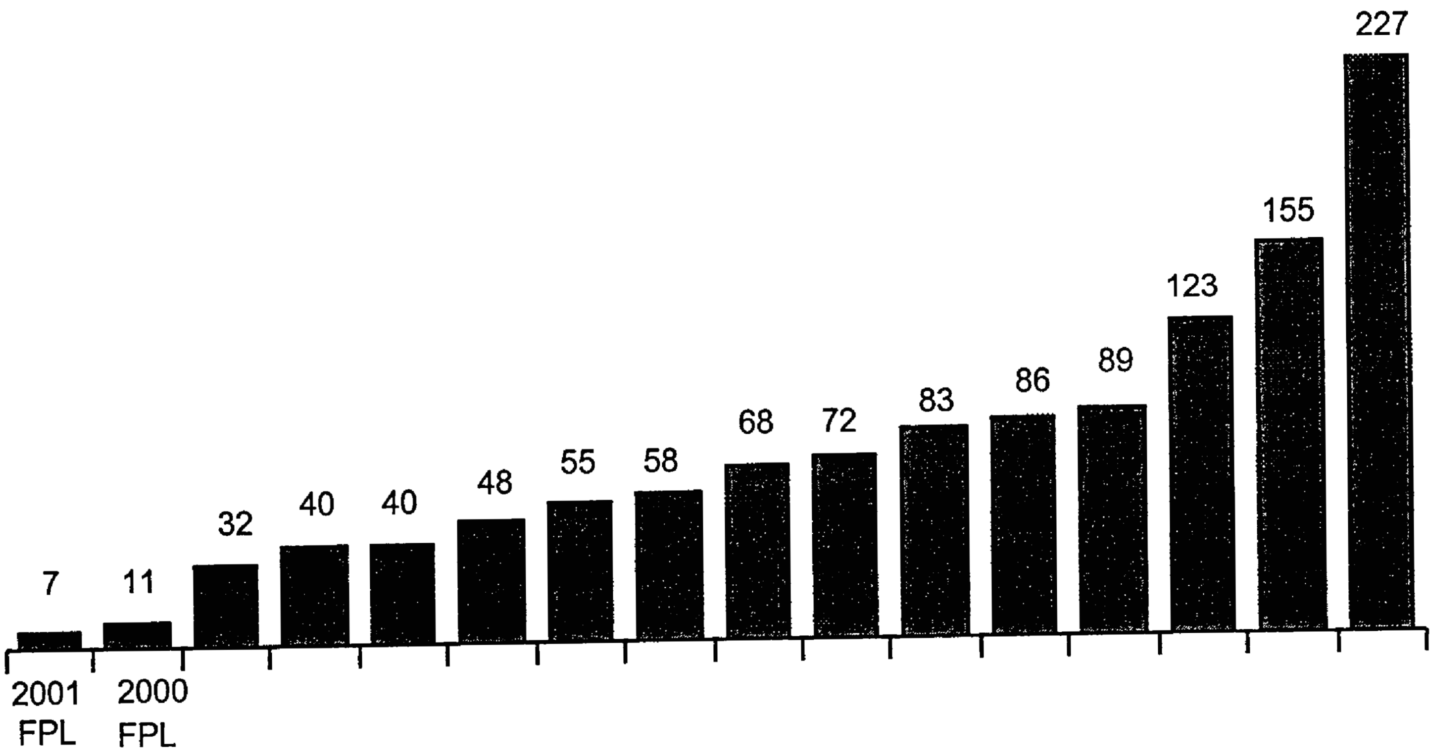
FPL Fossil Plants
OSHA Recordable Injuries



Docket No. 001148-EI
S. S. Waters Exhibit No.____
Document No. SSW-7, Page 1 of 1
FPL Fossil Plants OSHA Recordable Injuries

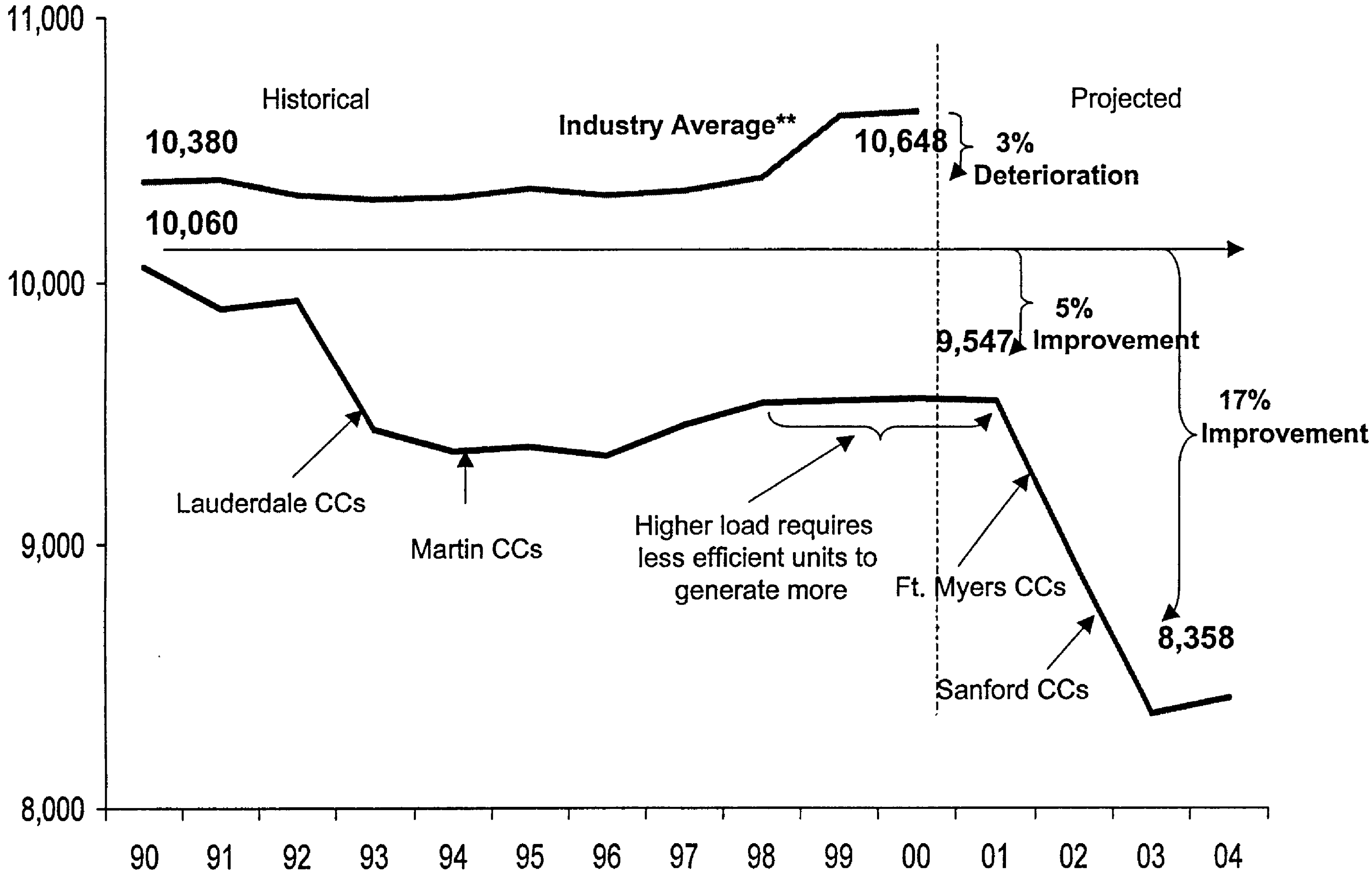
2000 EEI Safety Survey * Number of Serious Injuries

Fossil Plant



* Group 1 utilities - More than 7,000 employees

Fossil System Efficiency Trend Net Heat Rate (BTU/KWH)
FPL Fossil Plants



** Industry average (Source: RDI PowerDat) also includes non-regulated power plants starting in 1999.

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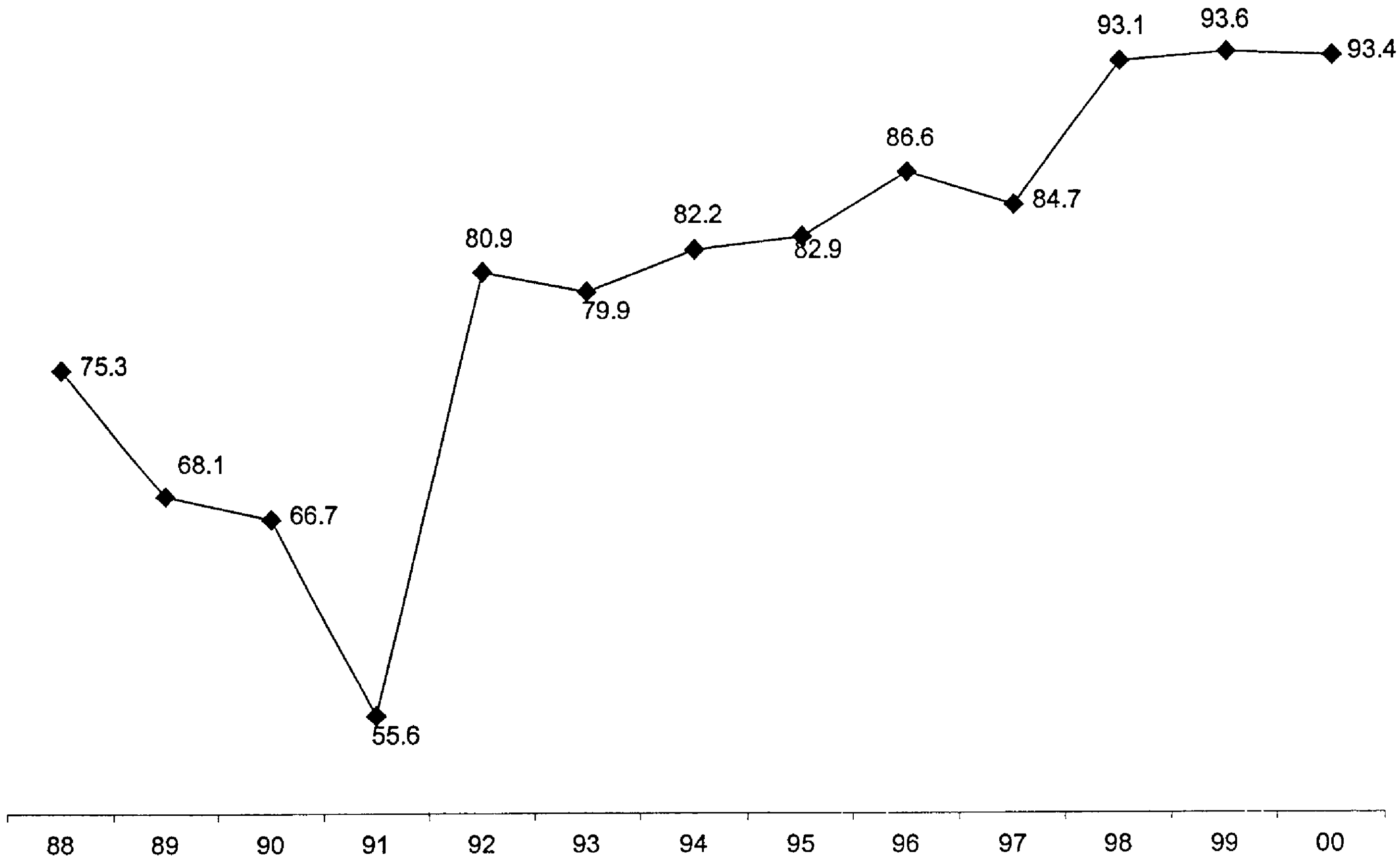
S. S. Waters Exhibit No. ____
Document No. SSW-9, Page 1 of 1
Fossil System Efficiency Trend Net Heat Rate

Equivalent Availability Factor*
(EAF %)
FPL Nuclear Plants



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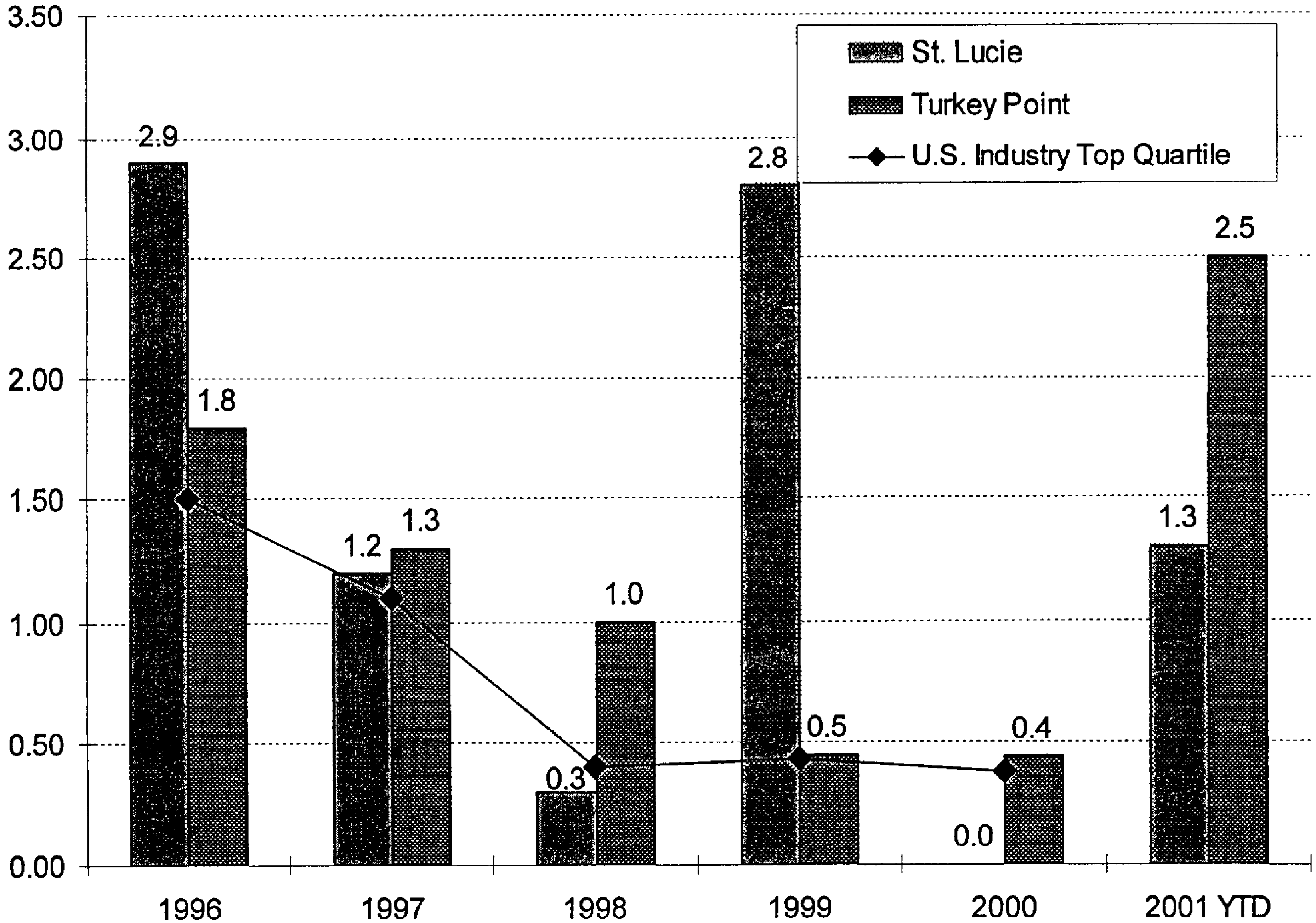
S. S. Waters Exhibit No. ____
Document No. SSW-10, Page 1 of 1
Equivalent Availability Factor

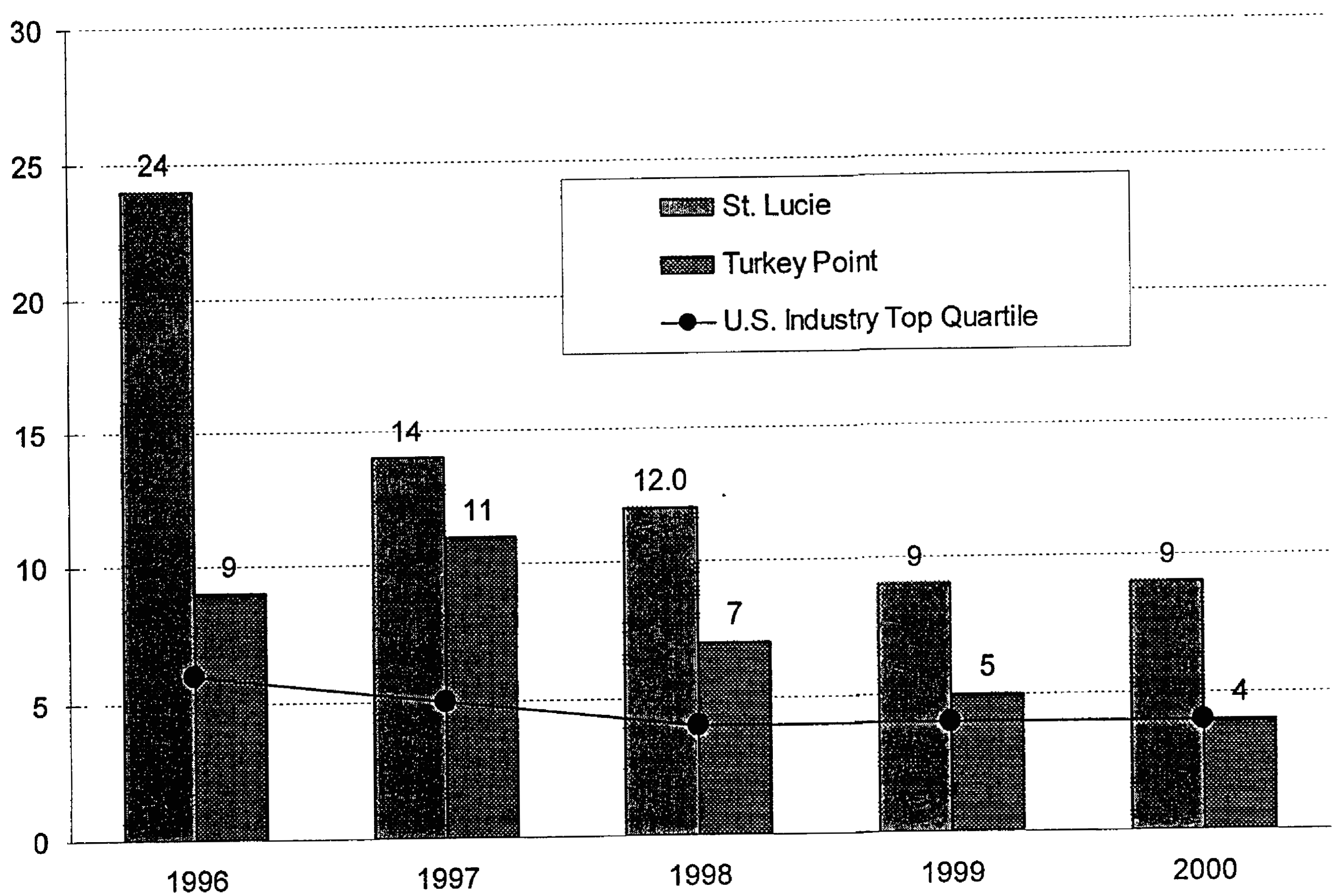
* EAF here includes all components (MOF, FOF, POF) reported by FPL annually to NERC

Equivalent Forced Outage Rate
(EFOR %)
FPL Nuclear Plants



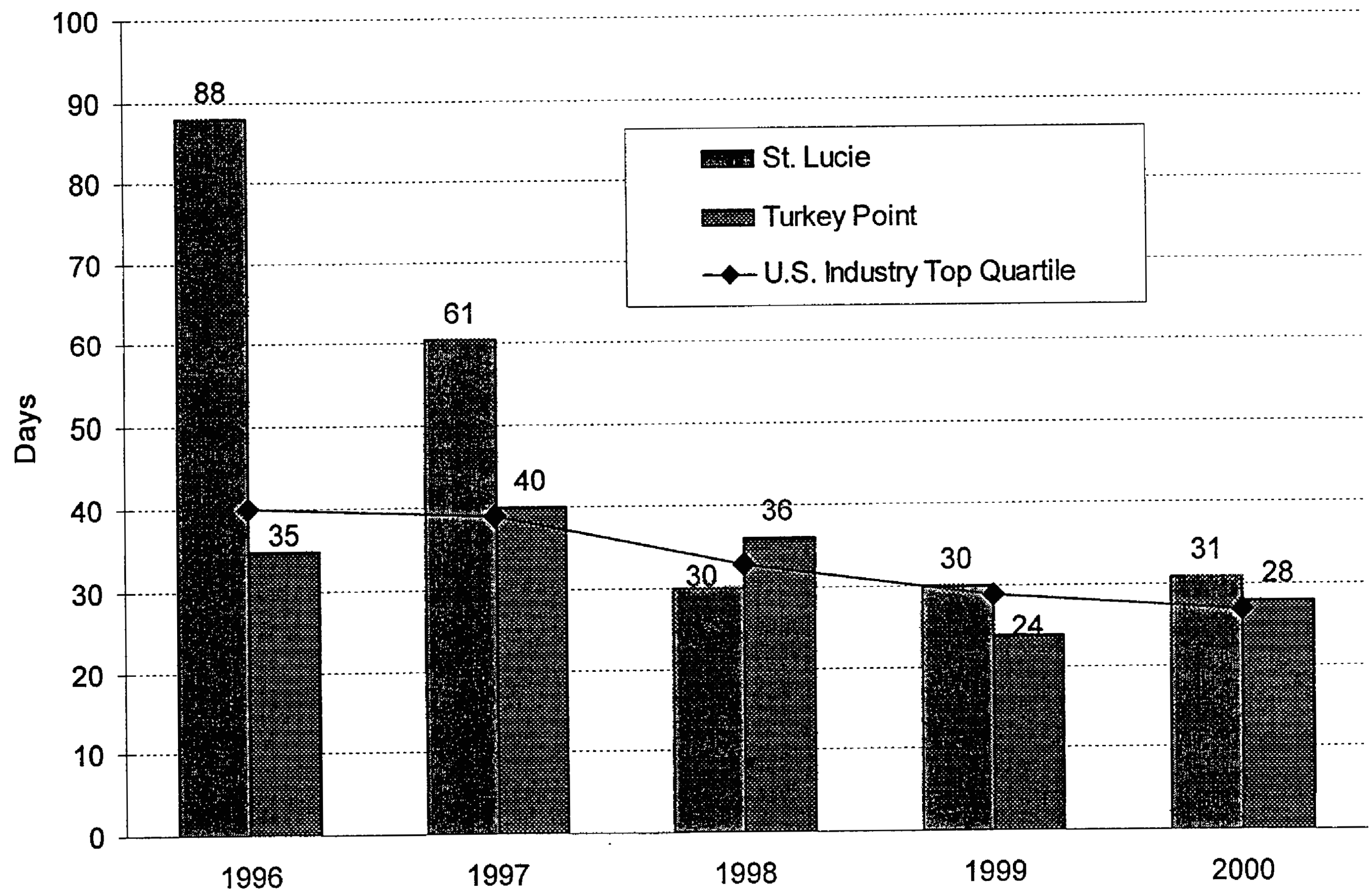
Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-11, Page 1 of 1
Equivalent Forced Outage Rate

OSHA Recordables



Docket No. 001148-EI
S. S. Waters Exhibit No. ___
Document No. SSW-12, Page 1 of 1
OSHA Recordables

Refueling Outage Durations



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S. S. Waters Exhibit No. ____
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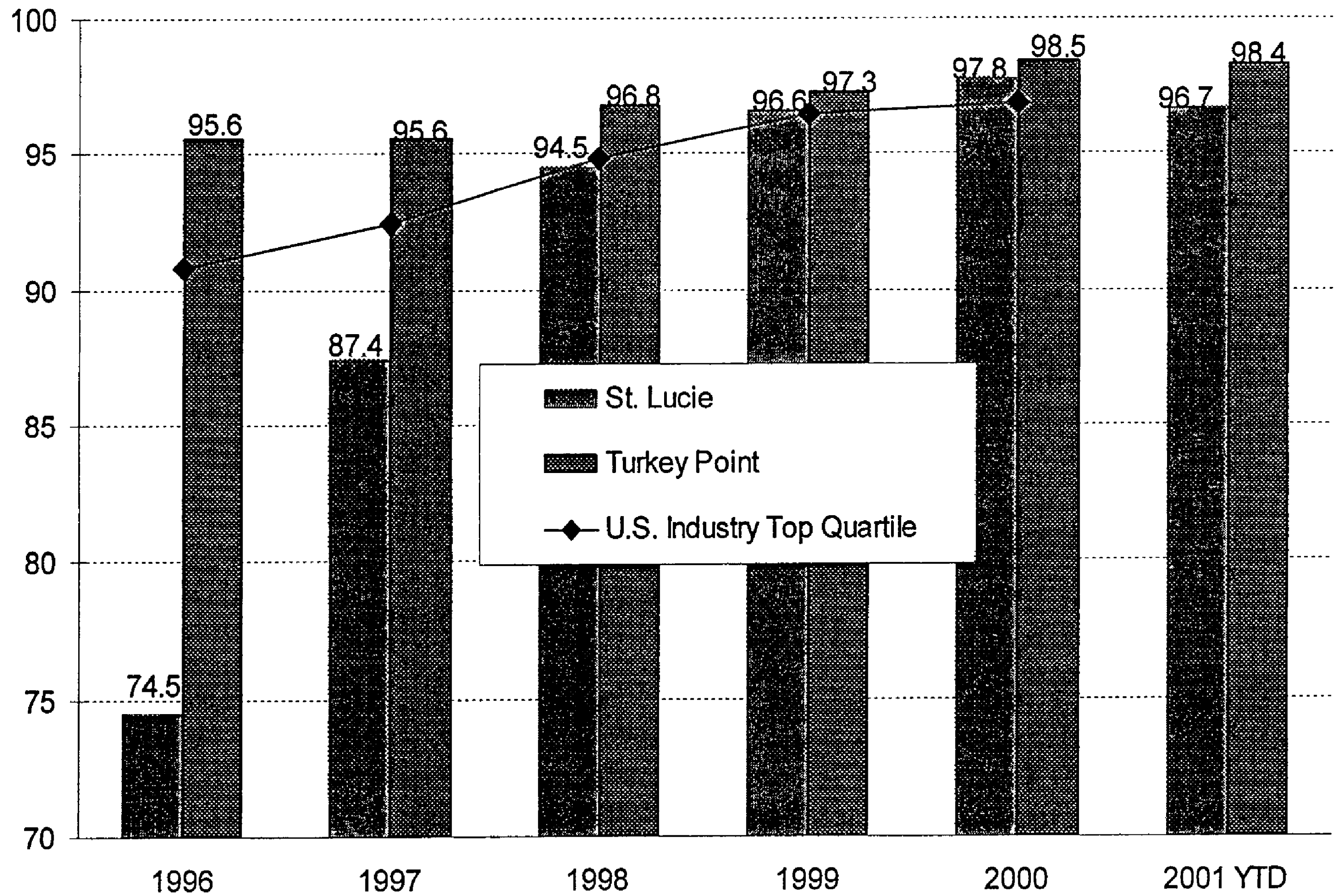
Refueling Outage Durations

WANO Index



Docket No. 001148-EI
S. S. Waters Exhibit No. ____
Document No. SSW-14, Page 1 of 1
WANO Index

SUMMARY OF DATA FROM 1988 FPL FERC FORM 1

	PLANT NAME FT. MYERS	PLANT NAME LAUDERDALE
Production Expenses:		
Operation Supervision and Engineering	432,649.00	376,183.00
Fuel	50,491,786.00	8,983,855.00
Coolants and Water (Nuclear Plants only)		
Steam Expenses	765,730.00	108,095.00
Steam From Other Sources		
Steam Transferred (Cr.)		
Electric Expenses	312,101.00	10,031.00
Misc. Steam (or Nuclear) Power Expenses	1,642,361.00	1,828,804.00
Rents		
Maintenance Supervision and Engineering	826,581.00	548,216.00
Maintenance of Structures	846,552.00	226,511.00
Maintenance of Boiler (or Reactor) Plant	1,542,879.00	738,717.00
Maintenance of Electric Plant	1,079,963.00	515,901.00
Maint. Of Misc. Steam (or Nuclear) Plant	480,185.00	447,647.00
Total Production Expenses	58,420,787.00	13,783,960.00

Docket No. 001148-EI
S. S. Waters Exhibit No. ______
Document No. SSW-15, Page 1 of 1
Summary of Data From 1988 FPL FERC Form 1

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Fort Myers Repowering

(2) **Capacity**

a. Summer	929	MW Incremental (1473 MW Total After Repowering)
b. Winter	1,073	MW Incremental (1617 MW Total After Repowering)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**

a. Field construction start-date:	2000
b. Commercial In-service date:	2002

(5) **Fuel**

a. Primary Fuel	Natural Gas
b. Alternate Fuel	None

(6) **Air Pollution and Control Strategy:** Dry Low Nox Combustors, Natural Gas

(7) **Cooling Method:** Once-through Cooling

(8) **Total Site Area:** 460 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**

Planned Outage Factor (POF):	3%
Forced Outage Factor (FOF):	1%
Equivalent Availability Factor (EAF):	96%
Resulting Capacity Factor (%):	96% (First Year)
Average Net Operating Heat Rate (ANHOR):	6,830 Btu/kWh

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sanford Unit 4 Repowering

(2) **Capacity**
a. Summer 567 MW Incremental (957 MW Total After Repowering)
b. Winter 671 MW Incremental (1065 MW Total After Repowering)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2000
b. Commercial In-service date: 2002

(5) **Fuel**
a. Primary Fuel: Natural Gas
b. Alternate Fuel: None

(6) **Air Pollution and Control Strategy:** Dry Low Nox Combustors and Natural Gas

(7) **Cooling Method:** Cooling Pond

(8) **Total Site Area:** 1,718 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): 3%
Forced Outage Factor (FOF): 1%
Equivalent Availability Factor (EAF): 96%
Resulting Capacity Factor (%): 96% (First Year)
Average Net Operating Heat Rate (ANHOR): 6,860 Btu/kWh

Schedule 9
Status Report and Specifications of Proposed Generating Facilities

(1) **Plant Name and Unit Number:** Sanford Unit 5 Repowering

(2) **Capacity**
a. Summer 567 MW Incremental (957 MW Total After Repowering)
b. Winter 671 MW Incremental (1065 MW Total After Repowering)

(3) **Technology Type:** Combined Cycle

(4) **Anticipated Construction Timing**
a. Field construction start-date: 2000
b. Commercial In-service date: 2002

(5) **Fuel**
a. Primary Fuel Natural Gas
b. Alternate Fuel Distillate

(6) **Air Pollution and Control Strategy:** Dry Low Nox Combustors, Natural Gas, 0.05% S. Distillate, & Water Injection on Distillate

(7) **Cooling Method:** Cooling Pond

(8) **Total Site Area:** 1,718 Acres

(9) **Construction Status:** P (Planned)

(10) **Certification Status:** P (Planned)

(11) **Status with Federal Agencies:** P (Planned)

(12) **Projected Unit Performance Data:**
Planned Outage Factor (POF): 3%
Forced Outage Factor (FOF): 1%
Equivalent Availability Factor (EAF): 96%
Resulting Capacity Factor (%): 96% (First Year)
Average Net Operating Heat Rate (ANHOR): 6,860 Btu/kWh

FPL Winter Peak Reserve Margin Assessment

Year	Firm Peak MW	Firm Capacity Import MW	Firm QF MW	Installed Capability MW (1)	Reserves MW	Reserve Margin %	Reserves Required to meet 15%	Additional Capacity Need MW
2001/2002	17,375	1,297	1,010	17,319	2,251	13.0	2,606	355
2002/2003	17,692	1,297	1,001	17,319	1,925	10.9	2,654	729
2003/2004	18,011	1,297	1,001	17,319	1,606	8.9	2,702	1,096
2004/2005	18,411	1,297	991	17,319	1,196	6.5	2,762	1,566
2005/2006	18,818	1,297	858	17,319	656	3.5	2,823	2,167
2006/2007	19,232	1,297	858	17,319	242	1.3	2,885	2,643

Source: 1998 FPL Ten Year Site Plan

(1) Assumes no capacity additions after 2000/2001

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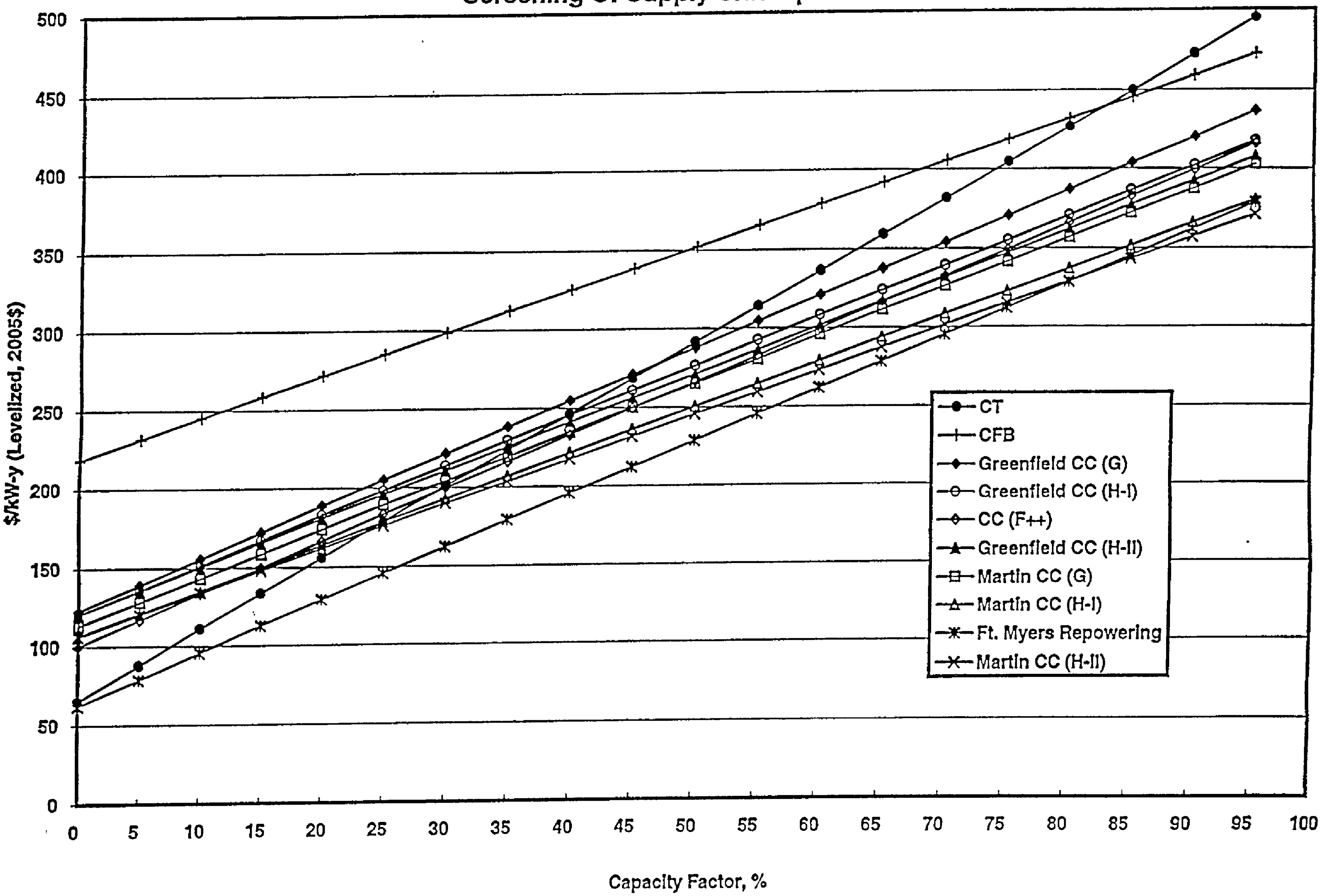
S. S. Waters Exhibit No. _____
Document No. SSW-17, Page 1 of 1
FPL Winter Peak Reserve Margin Assessment

Ft. Myers Repowering Analysis
Screening Of Supply Side Options



Docket No. 001148-EI
S. S. Waters Exhibit No. ______
Document No. SSW-18, Page 1 of 1
Ft. Myers Repowering Analysis

Ft. Myers Repowering Analysis
NPVRR Savings

Year	All Options (w/o Repowering) $(Millions)	Plan	All Options (w/ Repowering) $(Millions)	Plan
1997	1,451.00		1,451.00	
1998	1,415.00		1,415.00	
1999	1,397.00		1,397.00	
2000	1,481.00		1,481.00	
2001	1,584.00		1,584.00	
2002	1,703.00		1,703.00	
2003	1,862.00	F	1,860.00	PFMREP
2004	2,022.00	F	1,994.00	
2005	2,177.00		2,173.00	G
2006	2,380.00	MR5,6	2,365.00	MR5
2007	2,537.00		2,526.00	MR6
2008	2,764.00	F	2,750.00	H
2009	2,924.00	F	2,907.00	H
2010	3,263.00	3F	3,253.00	2H,F
2011	3,655.00	H	3,633.00	H
2012	3,884.00	H	3,858.00	H
2013	4,160.00	H	4,129.00	H
2014	4,420.00	F	4,383.00	H
2015	4,672.00	H	4,630.00	H
2016	4,918.00	H	4,879.00	F
2017	5,005.00		4,961.00	
2018	5,124.00		5,075.00	
2019	5,192.00		5,140.00	
2020	5,287.00		5,230.00	
2021	5,394.00		5,331.00	
2022	5,423.00		5,351.00	
2023	5,535.00		5,456.00	
2024	5,628.00		5,543.00	
2025	5,705.00		5,619.00	
2026	5,830.00		5,738.00	
NPV(@9.2%)	28,154.00		27,989.00	
NPV Savings				166

Notes:
- MR5,6 Martin 5 and 6; Comb. Cycle ATS-II Technology (6,081 Btu/kWh)
- F Comb. Cycle; F++ Technology
- H Greenfield; Comb. Cycle ATS-II Technology (6,081 Btu/kWh)
- G Greenfield Comb. Cycle G Technology
- CT Combution Turbine; G Technology
- CFB Circulating Fluidized Bed (coal)
- PFMREP Ft. Myers Repowering using F++ comb. Turb. Technology

COMBINED CYCLE PLANT CONSTRUCTION COST COMPARISON (1991 - 1999)

Operator Name	Plant Name	Year	Prime Mover Description	Demonstrated Capacity MW	Total Cost of Plant $	Tot. Cost $/demonstrated kW
Public Service Electric and Gas Company	Burlington (PSEG)	1994	COMBINED CYCLE	683	179753295	263
Nevada Power Co.	Clark (NEVP)	1994	COMBINED CYCLE	486	211445020	435
Alabama Power Co.	Washington County	1999	COMBINED CYCLE	109	47641239	437
Alabama Power Co.	GE Plastics	1999	COMBINED CYCLE	90	39508026	439
Delmarva Power & Light Co.	Hay Road	1993	COMBINED CYCLE	541	253684417	469
Florida Power & Light Company	Martin (FLPL)	1994	COMBINED CYCLE STEAM TURBINE WITH SUPPLEMENTARY FIRING	920	472064813	513
Farmington Electric Utility	Animas	1995	COMBINED CYCLE	50.1	25901341	517
Virginia Electric & Power Co.	Chesterfield	1993	COMBINED CYCLE	467	242307812	519
PSC of Colorado	Fort St. Vrain	1999	COMBINED CYCLE	492	260405270	529
Florida Power Corp.	Hines Energy Complex	1999	COMBINED CYCLE	505	274251718	543
Florida Power & Light Company	Lauderdale	1994	COMBINED CYCLE STEAM TURBINE WITH SUPPLEMENTARY FIRING	920	504652187	549
PUD No. 1 of Clark County	River Road Gen Stat	1998	COMBINED CYCLE	260	149535030	575
Hardee Power Partners, Ltd.	Hardee Power Station - SEC1	1993	COMBINED CYCLE COMBUSTION TURBINE	295	182237332	618
Portland General Electric	Coyote Springs	1995	COMBINED CYCLE	241	155091483	644
Ocean State Power II	Ocean State Power II	1993	COMBINED CYCLE	250	165986717	664
Hermiston Generating Co., L.P.	Hermiston Generating Co.	1996	COMBINED CYCLE	472	322543580	683
New York Power Authority	Richard M. Flynn	1995	COMBINED CYCLE	161	120725000	750
Maui Electric Co., Ltd.	Maalaea	1993	COMBINED CYCLE STEAM TURBINE WITH SUPPLEMENTARY FIRING	163.7	132779629	811
New England Power Co.	Manchester Street	1996	COMBINED CYCLE	495	431604688	872
Turlock Irrigation District	Almond	1999	COMBINED CYCLE	46.53	54984720	1182
Sacramento Municipal Utility District	Procter & Gamble	1997	COMBINED CYCLE	117	143210073	1224
Sacramento Municipal Utility District	Carson Ice	1995	COMBINED CYCLE	100.8	129340084	1283

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Document No. SSW-20, Page 1 of 1
Combined Cycle Plant Const. Cost Comparison 1999

Source RDI - POWERDAT Database Query: 11/01

Sanford 3,4 Repowering Analysis

Year	Base Case $(Millions)	Plan	Sanford Repowering $(Millions)	Plan
1997	1,445.00		1,445.00	
1998	1,404.00		1,404.00	
1999	1,462.00		1,462.00	
2000	1,468.00		1,468.00	
2001	1,574.00		1,574.00	
2002	1,689.00	PFMREP	1,689.00	PFMREP
2003	1,819.00		1,819.00	
2004	1,978.00	F	2,013.00	Sanford Repowering
2005	2,146.00	MR5	2,151.00	
2006	2,378.00	MR6	2,351.00	MR5
2007	2,514.00		2,520.00	MR6
2008	2,733.00	F	2,737.00	H
2009	2,896.00	F	2,903.00	F
2010	3,215.00	2H	3,210.00	2H
2011	3,667.00	2H,F	3,657.00	3H
2012	3,894.00	F	3,928.00	2H
2013	4,204.00	2H	4,188.00	H
2014	4,455.00	H	4,441.00	F
2015	4,703.00	F	4,689.00	F
2016	4,949.00	F	4,935.00	F
2017	5,027.00		5,011.00	
2018	5,130.00		5,112.00	
2019	5,193.00		5,174.00	
2020	5,274.00		5,254.00	
2021	5,368.00		5,346.00	
2022	5,380.00		5,358.00	
2023	5,478.00		5,454.00	
2024	5,559.00		5,534.00	
2025	5,635.00		5,609.00	
2026	5,744.00		5,716.00	
NPV(@9.2%)	28,062.00		28,045.00	
NPV Savings				18

Notes:	
MR5,6	Martin 5 and 6; Comb. Cycle ATS-II Technology (6,081 Btu/kWh)
F	Comb. Cycle; F++ Technology
H	Greenfield; Comb. Cycle ATS-II Technology (6,081 Btu/kWh)
G	Greenfield Comb. Cycle G Technology
CT	Combution Turbine; G Technology
CFB	Circulating Fluidized Bed (coal)
PFMREP	Ft. Myers Repowering using F++ comb. Turb. Technology

Fort Myers and Sanford Repowering Analysis

Year	Base Case ($,Millions)	Base Case Plan	Without Fort Myers Repowering ($,Millions)	Without Fort Myers Repowering Plan	Without Sanford Repowering ($,Millions)	Without Sanford Repowering Plan
2001	2254		2,254		2,254	
2002	2125	FM REP; SN 5 REP	2,170	2 Unsited CCs (Repl. FM REP); 1Unsited CC (Repl. SN 5 REP)	2,140	FM REP; 1Unsited CC (Repl. SN5 REP)
2003	2373	SN 4 REP; 2 CT @ FM	2,357	1Unsited CC (Repl. SN 4 REP); 2 CT@ FM	2,335	1Unsited CC (Repl. SN 4 REP); 2 CT@ FM
2004	2408		2,444		2,426	
2005	2718	MR Conversion to 4x1 CC; MT 4x1 CC	2,737	MR Conversion to 4x1 CC; MT 4x1 CC	2,722	MR Conversion to 4x1 CC; MT 4x1 CC
2006	2846		2,872		2,856	
2007	3079	4x1 Unsited CC	3,097	4x1 Unsited CC	3,083	4x1 Unsited CC
2008	3193		3,217		3,202	
2009	3454	4x1 Unsited CC	3,471	4x1 Unsited CC	3,459	4x1 Unsited CC
2010	3830	4x1 Unsited CC	3,850	4x1 Unsited CC	3,837	4x1 Unsited CC
2011	4113	4x1 Unsited CC	4,124	4x1 Unsited CC	4,113	4x1 Unsited CC
2012	4227		4,243		4,232	
2013	4322		4,339		4,328	
2014	4624	4x1 Unsited CC	4,634	4x1 Unsited CC	4,624	4x1 Unsited CC
2015	4803		4,806		4,800	
2016	5123	4x1 Unsited CC	5,113	4x1 Unsited CC	5,110	4x1 Unsited CC
2017	5263		5,257		5,253	
2018	5444	1 Unsited CT	5,440	1 Unsited CT	5,437	1 Unsited CT
2019	5634	2 Unsited CTs	5,631	2 Unsited CTs	5,629	2 Unsited CTs
2020	5903	4 Unsited CTs	5,901	4 Unsited CTs	5,899	4 Unsited CTs
2021	6052		6,051		6,049	
2022	6274		6,270		6,273	
2023	6384		6,375		6,380	
2024	6503		6,494		6,500	
2025	6686		6,678		6,685	
2026	6848		6,842		6,850	
2027	6966		6,964		6,971	
2028	7103		7,102		7,112	
2029	7260		7,256		7,267	
2030	7399		7,394		7,405	
NPV (@8.5%)	43,700		43,840		43,714	
Savings (Total)			140		14	

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Document No. SSW-23, Page 1 of 1
Revised Load Forecast

Revised Load Forecast
(Net Energy For Load & Customers)

Year	Net Energy for Load (NEL) (gWh)	% Change	Revised NEL (gWh)	% Change	Difference	Absolute Customer Growth	Revised Absolute Customer Growth	Difference	NEL/ Customer kWh	% Change	Revised NEL/ Customer kWh	% Change	Difference
2001	99,704	3 9%	99,162	3 3%	-0.6%	86,760	86,606	-0.2%	25,337	1.6%	25,032	0 4%	-1.2%
2002	103,223	3.5%	100,158	1 0%	-2 5%	85,643	65,000	-24.1%	25,672	1.3%	25,039	0 0%	-1 3%

Actual 2001 Data:		2001 Error vs. Revised Forecast:
NEL	98,435 gWh	-0.7%
Absolute Customer Growth	86,880 Customers	0 3%
NEL/Customer	25,014 gWh/customer	-0.1%

Docket No. 001148-EI
S. S. Waters Exhibit No. _______
Document No. SSW-24, Page 1 of 1
FPL Impact of Economic Recession on Demand for Electricity

FLORIDA POWER & LIGHT COMPANY
IMPACT OF ECONOMIC RECESSIONS ON DEMAND FOR ELECTRICITY
(INCOME, CUSTOMERS GROWTH AND USE OF ELECTRICITY PER CUSTOMER)

Year	Florida Real Per Capita Income (Chained $1996)	% Change	Customers	Absolute Change	% Change	Use Per Customer (KWH)	% Change
1972	15,440		1,446,114			21,782	
1973	16,323	5.7%	1,567,638	121,524	8.4%	22,445	3.0%
1974	15,957	-2.2%	1,676,022	108,384	6.9%	[illegible]	-5.7%
1975	15,482	[illegible]	[illegible]	62,050	3.7%	[illegible]	[illegible]
1976	15,858	2.4%	1,795,793	57,721	3.3%	21,225	-0.7%
1977	16,336	3.0%	1,875,821	80,028	4.5%	21,704	2.3%
1978	17,201	5.3%	1,967,352	91,531	4.9%	22,215	2.4%
1979	17,720	3.0%	2,074,327	106,975	5.4%	21,859	-1.6%
1980	18,119	2.3%	2,184,974	110,646	5.3%	22,174	1.4%
1981	18,574	2.5%	2,285,187	100,214	4.6%	21,890	-1.3%
1982	18,503	-0.4%	2,358,167	72,980	3.2%	21,429	-2.1%
1983	19,021	2.8%	2,429,688	71,521	3.0%	21,608	0.8%
1984	19,977	5.0%	2,520,523	90,835	3.7%	21,086	-2.4%
1985	20,638	3.3%	2,617,556	97,033	3.8%	21,393	1.5%
1986	21,130	2.4%	2,723,555	105,999	4.0%	21,394	0.0%
1987	21,670	2.6%	2,840,207	116,651	4.3%	21,694	1.4%
1988	22,346	3.1%	2,953,663	113,457	4.0%	21,910	1.0%
1989	23,127	3.5%	3,064,436	110,773	3.8%	22,828	4.2%
1990	23,044	-0.4%	3,158,817	[illegible]	3.1%	22,486	-1.5%
1991	22,662	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	0.8%
1992	22,505	[illegible]	[illegible]	54,783	1.7%	22,277	-1.8%
1993	23,024	2.3%	3,355,794	74,556	2.3%	22,580	1.4%
1994	23,296	1.2%	3,422,187	66,393	2.0%	23,487	4.0%
1995	23,963	2.9%	3,488,796	66,609	1.9%	24,066	2.5%
1996	24,558	2.5%	3,550,747	61,951	1.8%	23,937	-0.5%
1997	25,184	2.5%	3,615,485	64,738	1.8%	24,022	0.4%
1998	26,095	3.6%	3,680,470	64,985	1.8%	25,177	4.8%
1999	26,442	1.3%	3,756,009	75,539	2.1%	24,350	-3.3%
2000	27,260	3.1%	3,848,350	92,341	2.5%	24,943	2.4%

Note: Shaded areas represent recession years.

Unemployment Rates

State of Florida and Selected Florida Counties

Year	Florida	County: Brevard	Broward	Collier	Duval	Hills-borough	Lee	Miami-Dade	Orange	Palm Beach	Pinellas	Volusia
1980	5.9	5.4	4.1	6.3	4.7	5.0	4.7	8.0	5.4	4.9	4.7	5.6
1981	6.8	6.5	4.8	8.4	5.8	5.8	5.3	9.4	6.3	5.8	5.0	6.2
1982	**8.2**	**7.0**	**6.7**	$\boxed{\mathbf{12.0}}$	**6.8**	**7.9**	**7.9**	$\boxed{\mathbf{10.0}}$	**6.8**	**7.6**	**6.3**	**7.0**
1983	8.6	7.6	7.3	12.2	7.8	8.3	8.1	9.8	7.3	8.5	6.6	7.4
1984	6.3	5.1	5.0	8.4	5.6	5.3	5.3	7.8	5.4	6.3	4.4	5.2
1985	6.0	4.7	4.9	7.3	5.1	5.3	4.8	7.5	4.9	6.2	4.2	4.8
1986	5.7	6.0	4.5	5.9	5.4	5.7	4.2	6.7	4.7	5.9	4.2	5.0
1987	5.3	5.5	4.2	4.9	5.4	5.1	3.8	5.8	4.7	5.4	4.2	4.7
1988	5.0	4.7	4.1	4.3	5.4	4.5	3.6	5.4	4.6	5.0	4.4	4.5
1989	5.6	5.2	5.1	4.6	5.8	4.9	3.9	6.4	5.0	6.0	4.7	5.4
1990	**6.0**	**5.3**	**5.6**	**5.4**	**5.2**	**4.7**	**3.8**	$\boxed{\mathbf{7.8}}$	**5.4**	$\boxed{\mathbf{7.0}}$	**4.5**	**5.0**
1991	**7.4**	**7.0**	$\boxed{\mathbf{7.7}}$	$\boxed{\mathbf{7.8}}$	**6.3**	**6.1**	**6.0**	$\boxed{\mathbf{9.4}}$	**6.8**	$\boxed{\mathbf{8.9}}$	**6.0**	**6.5**
1992	**8.3**	**7.9**	$\boxed{\mathbf{8.5}}$	$\boxed{\mathbf{9.5}}$	**6.8**	**7.1**	**7.4**	$\boxed{\mathbf{10.5}}$	**7.4**	$\boxed{\mathbf{10.3}}$	**6.6**	**7.6**
1993	7.0	7.6	6.9	8.4	5.5	6.4	5.7	8.2	6.2	9.0	6.0	6.7
1994	6.6	7.4	6.5	8.2	4.9	5.2	4.9	8.4	5.7	8.8	5.0	6.2
1995	5.5	6.5	5.7	7.0	3.8	4.3	4.2	7.4	4.5	7.2	4.1	4.8
1996	5.1	5.4	5.1	5.8	3.8	3.8	3.8	7.3	3.8	6.6	3.7	4.3
1997	4.8	4.6	4.9	5.0	3.8	3.3	3.4	7.1	3.3	6.3	3.4	3.9
1998	4.3	4.3	4.5	4.2	3.2	2.8	3.0	6.4	3.0	5.6	3.1	3.4
1999	3.9	3.9	4.1	3.7	3.1	2.6	2.6	5.8	2.7	5.0	2.7	3.1
2000	3.6	3.4	3.7	3.5	3.3	2.6	2.6	5.3	2.5	4.4	2.5	2.9

$\boxed{}$ County's unemployment rate is greater than state

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Unemployment Rates

GROWTH IN PER CAPITA INCOME

		County										
Year	Florida	Brevard	Broward	Collier	Duval	Hills-borough	Lee	Miami-Dade	Orange	Palm Beach	Pinellas	Volusia
1981	2.5%	3.9%	0.7%	3.8%	3.4%	3.3%	1.8%	1.0%	4.1%	6.5%	4.7%	1.5%
1982	**-0.4%**	**-2.1%**	**-0.4%**	**-3.9%**	**1.5%**	**1.1%**	**-4.1%**	**-0.8%**	**2.1%**	**-0.7%**	**0.0%**	**-0.8%**
1983	2.8%	2.1%	2.8%	4.5%	2.3%	3.3%	3.0%	1.4%	3.0%	5.6%	2.1%	3.5%
1984	5.0%	5.2%	6.2%	5.2%	7.6%	6.0%	4.4%	3.6%	5.6%	5.1%	5.2%	4.7%
1985	3.3%	2.5%	3.1%	3.0%	3.6%	3.4%	5.1%	2.2%	3.9%	5.2%	2.3%	3.5%
1986	2.4%	2.3%	0.1%	4.6%	2.1%	1.5%	3.0%	1.1%	2.3%	2.4%	3.1%	2.4%
1987	2.6%	2.7%	2.0%	7.6%	2.0%	2.8%	2.9%	2.9%	2.0%	4.8%	0.7%	1.3%
1988	3.1%	1.8%	3.0%	12.7%	1.1%	2.5%	4.1%	1.0%	3.0%	4.8%	2.0%	1.8%
1989	3.5%	4.0%	3.7%	1.5%	3.6%	3.2%	6.1%	2.0%	1.0%	4.3%	5.7%	1.7%
1990	**-0.4%**	**-0.8%**	**-2.3%**	**-2.0%**	**0.3%**	**1.8%**	**-2.0%**	**-0.9%**	**-0.8%**	**2.9%**	**-2.9%**	**-1.9%**
1991	**-1.7%**	**-3.4%**	**-2.2%**	**-1.9%**	**-1.7%**	**0.2%**	**-3.7%**	**-2.2%**	**-1.3%**	**2.0%**	**-2.4%**	**-3.4%**
1992	**-0.7%**	**-1.3%**	**0.7%**	**6.3%**	**0.8%**	**1.4%**	**0.8%**	**-8.3%**	**0.5%**	**-0.4%**	**0.9%**	**-0.6%**
1993	2.3%	0.4%	-1.2%	3.3%	2.3%	1.4%	0.3%	11.8%	1.4%	-0.4%	3.7%	0.2%
1994	1.2%	-0.1%	0.1%	4.5%	2.3%	3.1%	1.8%	0.1%	0.6%	0.5%	0.0%	1.7%
1995	2.9%	2.4%	1.0%	1.1%	3.2%	4.3%	4.0%	1.8%	3.0%	3.4%	3.8%	3.3%
1996	2.5%	1.2%	1.3%	3.7%	2.2%	3.4%	1.0%	1.3%	2.7%	3.3%	2.9%	3.1%
1997	2.5%	0.3%	4.0%	6.2%	2.2%	3.5%	4.0%	0.9%	3.3%	-1.0%	4.7%	2.9%
1998	3.6%	2.7%	2.5%	1.1%	4.4%	4.6%	3.0%	3.6%	5.1%	3.6%	4.0%	2.2%
1999	1.3%	1.0%	0.2%	1.6%	2.0%	3.1%	0.3%	1.0%	4.7%	1.4%	3.2%	0.7%
2000	3.1%	1.4%	1.1%	2.4%	2.4%	2.5%	1.1%	1.6%	0.7%	1.6%	1.8%	1.0%

$\boxed{}$ County's Growth in Per Capita Income is less than state