BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110009-EI
FLORIDA POWER & LIGHT COMPANY

MARCH 1, 2011

EXTENDED POWER UPRATES - 2010

TESTIMONY & EXHIBITS OF:

WILLIAM DERRICKSON

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DIRECT TESTIMONY OF WILLIAM B. DERRICKSON

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Section I: Background and Experience

Q. Please state your name and address.

A. My name is William B. Derrickson. My address is 1813 Eagles Glen Cove, Austin, Texas 78732.

Q. By whom are you employed and what is your position?

A. I am the president of WPD Associates.

Q. Please describe WPD Associates.

A. WPD Associates is a small, private consulting company specializing in project management.

Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Electrical Engineering from the University of Delaware and completed the Program for Management Development at the Harvard

Business School. I also completed a number of other management-related courses, a complete list of which are included in my resume (Exhibit WBD-1).

I have been involved with the power and chemical industries for the past forty seven years, beginning in 1964 as an electrical maintenance engineer at the Indian River Power Plant in Delaware. I spent approximately two years with Hercules Incorporated designing and starting up instrumentation and control systems for chemical plants. I entered the nuclear power industry as an electrical startup engineer at Florida Power & Light Company's (FPL) Turkey Point nuclear power plant in 1970. I was appointed Startup Coordinator in 1971; Construction Supervisor for the St. Lucie Unit 1 project in 1973; Project General Manager for major retrofit projects at Turkey Point in 1975; and Project General Manager of the St. Lucie Unit 2 project in 1977. I was promoted to Director of Projects in 1983.

In 1984 I accepted the position of Senior Vice President of Nuclear Power for Public Service Company of New Hampshire, responsible for completing and operating the Seabrook Nuclear Power Plant.

Following completion of the Seabrook Plant in 1988, I joined Quadrex Corporation, a small specialty environmental company. In 1993 I left Quadrex and formed a consulting company to assist clients with the management of major projects. I have also served as an expert witness in a number of cases, the most significant of which are detailed in my resume.

Q. Please expand upon your experience with nuclear power plants, and specifically your experience with major construction programs at these plants.

A. I entered the nuclear power industry as an electrical startup engineer at the Turkey Point Plant in 1970, and was promoted to the position of Startup coordinator in 1971. As Startup Coordinator I was responsible for the testing of plant systems and components to verify their performance to the requirements of the final safety analysis report, and to turn the systems over to the plant operating department once performance was demonstrated.

In 1973 I was appointed Construction Supervisor for the St. Lucie Unit 1 project. In that position I was FPL's site representative to oversee all construction activities. We established oversight in the areas of planning and scheduling, quality control, testing, and productivity to assure that the site activities were performed as efficiently as reasonably possible and that the plant was being constructed in accordance with applicable codes and standards. In 1975 I was appointed Assistant Project General Manager for the St. Lucie Unit 1 project with the mission of completing the project and commencing commercial operation.

In January 1977 I was appointed Project General Manager for the St. Lucie Unit 2 project. At that time FPL was performing an alternate site study mandated by the Nuclear Regulatory Commission (NRC) as well as working on plant design. The late 1970s and early 1980s were particularly challenging and dynamic times in the nuclear industry, following the formation of the NRC in 1974. As a result, numerous new regulatory requirements were continually being issued. These were, among others, in the areas of security, pipe supports, concrete anchors, fire protection, seismic conditions, and other requirements as a result of the accident at Three Mile Island (TMI) Unit 2 in 1979. The continuously emerging regulatory requirements made it very difficult for the engineers to complete the plant design. However, with the support of FPL senior management and a qualified and dedicated project team, the plant commenced commercial operation only two months behind the original 72-month schedule. This was accomplished despite having to address nearly a thousand new regulations and recover from extensive damage caused to the plant as a result of hurricane David in September 1979.

More on the St. Lucie Unit 2 project is explained in a paper presented at a 1982 meeting of the Project Management Institute (PMI) (Exhibit WBD-2). In the paper, Chart 22 lists 12 "Ingredients for a Successful Project" identified by the St. Lucie 2 project team in 1982, which, as discussed below, I have used in my evaluation of FPL's performance on the Extended Power Uprate (EPU) Project in 2010. Another paper (Exhibit WBD-3) describes the 12 "Ingredients" in more detail. The St. Lucie Unit 2 success was also recognized by Engineering News Record Magazine with an article entitled "Nuclear Construction-Doing it Right" featured in its April 23, 1983 edition (Exhibit WBD-4).

The 12 ingredients for a successful project were identified by the St. Lucie 2 project team in 1982 as a result of a request from the NRC as to how FPL was able to achieve its schedule objectives while the rest of the nuclear power industry was struggling. Since 1982 organizations such as PMI, the International Organization for Standardization and the International Atomic Energy Agency have subsequently produced project management guidelines that now also have memorialized either identical or similar criteria for managing projects.

In 1984 I joined Public Service Company of New Hampshire as Senior Vice President of Nuclear Energy, responsible for completing and operating the Seabrook Nuclear Plant. When I arrived in New Hampshire in 1984, the project was plagued with virtually every nuclear power plant construction problem I had ever experienced. There was a schedule slip annually with accompanying cost estimate increases. Project staff working on the project was located in Philadelphia, PA, Framingham, MA, Manchester, NH and Pittsburgh, PA as well as at the site, and there were over 10,000 people on the project. When I assumed responsibility for the project, I employed the 12 ingredients from the St. Lucie Unit 2 project. I reduced staff, moved virtually all project personnel to the site, brought on qualified management, and developed a realistic schedule and estimate. The plant was completed and fuel was loaded into the reactor in November 1986. After successfully completing and testing a utility developed emergency plan for New Hampshire, Maine and Massachusetts – a project in and of itself – the operating license was issued in January 1990.

I accepted another challenging assignment in 1986 as Nuclear Advisor to the Board of the Tennessee Valley Authority (TVA). TVA owned nine nuclear units: three Brown's Ferry units and two Sequoyah units, all of which were in operation; two units under construction at the Watts Bar site; and two which were partially constructed but with no ongoing activity at the Bellefonte site.

In 1985 a problem developed with welding at the Watts Bar plant and an independent company was retained to evaluate the situation. The reviewer appeared on Sixty Minutes and portrayed TVA in such an unfavorable light that its management voluntarily shut down the five operating units to inspect all welding. Upon completion of this welding inspection the NRC informed TVA that it had more work to do in order to get permission for the units to return to service. After a year of insufficient progress, I was retained as an Advisor to the TVA Board to facilitate getting the operating plants back on line and the two Watts Bar units completed. The situation I found at TVA was similar to what I had found at Seabrook. By 1987 there were approximately 16,000 people working on the seven units with little progress being made.

I advised the chairman of the TVA board that he needed to reduce the workforce by 10,000, and determine which unit was in the best shape and focus on that unit first. I then suggested scheduling work on the next units about eighteen months apart since NRC staff had limited resources to review TVA's documentation. That plan was generally accepted and successfully executed.

Q. Please describe your experience with major nuclear plant retrofit projects.

A. When St. Lucie Unit 1 was placed into commercial service in 1976, it was done with conditions to the NRC operating license. There were items which required completion at future milestones such as prior to power escalation, first refueling outage, or a specific future date. All such items were retrofitted into the completed plant. Most items were small on an individual basis, but were significant in total as the cost exceeded $20 million. Additionally, there were numerous regulatory changes that required plant modifications after the unit was completed. Examples of regulatory changes were new security requirements, post-TMI modifications memorialized in NUREG 0737, and the promulgation of new NRC fire protection regulations in 1981.

I was also responsible for two major retrofit and/or repair projects at Turkey Point. The first was the increase of storage capacity of the spent fuel pools at both units. The original design of the plant was for storage of one and one third reactor cores of fuel. Due to the lack of a facility to which to take spent fuel, it became necessary to increase the storage capacity of the pools to the maximum possible at that time. The pools in both units 3 and 4 were so increased. This work had to be accomplished so as not to impact the operation of either unit. It required moving fuel from one unit's pool to the other and back. The pools were also improved with heavier grade steel liners and leak detection.

I was also responsible for initiating and organizing the steam generator replacement project at Turkey Point. This project commenced in 1976 with the construction of a scale model of the reactor containment building. This enabled the job to be done on the model to determine all requirements for removal of structural steel, equipment, stairways etc. It also was helpful in determining how to get the steam generators in and out of the containment building without cutting the containment concrete. All six steam generators in both units were successfully replaced and remain in operation today.

I was also involved with the repair of the reactor core barrel which was damaged by the vibration of a thermal shield anchored on the core barrel at St. Lucie Unit 1. The project entailed cutting the thermal shield into strips that could be taken out through the fuel transfer tube, drilling crack arrestor holes in the core barrel, making nuclear qualified plugs to insert into the holes, and returning the reactor and refueling cavity to nuclear clean condition. It was later determined that the thermal shield was no longer necessary and replacement was not required. The entire project had to be done under water with remote tools due to the radioactivity in the reactor and its components. Many tools utilized to repair the core barrel were invented for the purpose of this project. The entire effort took fifty weeks. The plant was successfully returned to service and has been running well since.

Q. Have you testified previously in this case?

A. No

Q. Are you sponsoring any exhibits in this case?

A. Yes. I am sponsoring twelve (12) exhibits. They are:

Exhibit WBD-1:	My personal resume
Exhibit WBD-2:	"A Nuclear Plant Built on Schedule", a paper I wrote about how the St. Lucie Unit 2 project was managed
Exhibit WBD-3:	"Achieving Project Goals in Contrasting Environments-The Value of a Strong Management Philosophy", a paper written by me and George Bradshaw
Exhibit WBD-4:	"Nuclear Construction-Doing it Right", an article from ENR magazine
Exhibit WBD-5:	Chronology of Nuclear Power Event and Regulations
Exhibit WBD-6:	Cumulative Regulatory Changes (1968-1985)
Exhibit WBD-7:	The list of persons with whom I discussed the EPU Project
Exhibit WBD-8:	The list of documents reviewed
Exhibit WBD-9:	Photographs of the Turkey Point Plant
Exhibit WBD-10:	Photographs of the St. Lucie Plant

Exhibit WBD-11: PTN3R25 and 4R26 EPU Outage Details

Exhibit WBD-12: PSL EPU Outage Details

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to opine on the prudence of EPU project management in 2010.

Q. Please summarize your testimony.

A. Based upon my review of relevant controls, procedures, and business documents, my interviews with various project personnel, and site visits, my conclusion is that FPL prudently managed the EPU project in 2010. Overall, FPL is employing the 11 applicable "Ingredients" for a successful project, which include (i) management commitment; (ii) financial resources; (iii) realistic and firm schedules; (iv) clear decision-making authority; (v) flexible project control tools; (vi) teamwork-individual commitment; (vii) engineering ahead of construction; (viii) early start-up involvement; (ix) organizational flexibility; (x) ongoing project critique; and (xi) owner leadership. These ingredients reflect industry-standard project management principles, and in my experience, are good indicators that a project is being prudently and reasonably managed. This conclusion is supported by the successful outage work that occurred in 2010.

Q. Please describe how the remainder of your testimony is organized.

A. Section 2 of my testimony provides a perspective on the evolution of the nuclear power industry which established the criteria under which all plants were licensed. I show why there are significant differences between plants and units such as Turkey

Point, St. Lucie Unit 1, and St. Lucie Unit 2. In this section I also show why projects such as the EPU Project pose challenges not found in the construction of new plants. Section 3 of this testimony details my review of FPL's management of the EPU project in 2010, which includes an evaluation of EPU management performance against the "Ingredients for a Successful Project." I also provide my review of and opinion on 2010 outage activities.

Section 2: Turkey Point, St. Lucie Unit 1 and St. Lucie Unit 2 in Perspective

Q. At a conceptual level, how are the Turkey Point and St. Lucie plants different?

A. As can be seen from the chronology attached as Exhibit WBD-5, the Turkey Point units were designed and constructed in a different regulatory era than the St. Lucie units. And, while the two St. Lucie units may look alike, there are significant differences between them as well. Exhibit WBD-5 lists the significant events in the evolution of the nuclear power industry and where the four FPL nuclear units fit into this timeline. Exhibit WBD-6 shows the cumulative number of regulatory changes issued between 1968 and 1985.

As can be seen from these exhibits, the Turkey Point units were designed and constructed at a time of few regulations, and regulated by the Atomic Energy Commission. For the first three years of the project, 10 CFR Appendix B, quality assurance requirements for nuclear power plants, did not exist. Thus, it was possible to build these units smaller, with shared facilities, adjacent to fossil units, and with a less stringent security system. Additionally, the Turkey Point units were completed with less than 200 regulations in effect. FPL was required to comply with just less than 400 to secure the St. Lucie Unit 1 operating license. While St. Lucie 2 was under construction an additional approximately 1000 regulations were promulgated with which FPL was required to comply.

Primarily as a result of the evolution of the regulatory and industry codes and standards, nuclear power plants changed with time. Each plant was required to be designed to the regulatory requirements in effect at the time it was licensed. Thus, St. Lucie Unit 1 incorporates more standards than Turkey Point, and St. Lucie Unit 2 incorporates more standards than St. Lucie Unit 1. For example, St. Lucie 2 was required to be designed to higher seismic criteria, to include full compliance with NRC fire protection regulations, and to have all post-TMI requirements incorporated before it could be licensed.

Some of the more prominent features that distinguish the Turkey Point plant from the St. Lucie units are that Turkey Point has a common control room as opposed to separate control rooms at St. Lucie; a shared reactor auxiliary building at Turkey Point as opposed to separate auxiliary buildings at St. Lucie; a single containment for each Turkey Point unit as opposed to concentric containments with an air space between the St. Lucie units; the Turkey Point building volume is about half the building volume of the St. Lucie units; Turkey Point is located next to fossil units, and, as licensed, the two Turkey Point units shared two emergency diesel generators, where at St. Lucie each unit has two emergency diesel generators.

Q. How do the differences you described affect the management of the EPU?

A. In addition to requiring new plants to be designed differently, many of the nearly 1,400 regulations issued between 1968 and 1985 as well as regulations promulgated since 1985 also affect the ongoing operation of the plants. One such set of regulations addresses plant security. Due to increasing concerns about threats such as terrorism, nuclear plant security has been escalated so that projects such as the EPU have to factor additional time into the schedule for processing personnel and material into the plant. This is especially onerous at Turkey Point where the nuclear units are adjacent to the fossil units, and the security barriers between the nuclear and fossil units make entry and exit extremely difficult. As a result, access to the secondary side of the nuclear units (turbine structure) is limited.

St. Lucie enjoys a much better arrangement. Even though the two St. Lucie units are close together, they are both nuclear units and are both inside one security boundary. Thus, access and logistics are considerably easier. This can be seen in the photographs included as Exhibit WBD-10. In Exhibit WBD-9, the photos show the access to the Turkey Point turbine building. As can be seen in these photos there is virtually no access from the north, via the fossil plant end of the turbine building due to the security fencing and razor wire. The photos in Exhibit WBD-9 also show the overall tight conditions at Turkey Point. At St. Lucie, however, as can be seen in Exhibit WBD-10, the photos show that considerably more room is available for storage and access. Thus, EPU modifications are significantly more difficult at Turkey Point.

Another result of the vintage and age of the Turkey Point units is that the plant was designed and built to codes and standards that are no longer applicable. As a result, when new work is planned, other work may be required to permit the licensing of the new work. The plant's age also is a factor. As equipment ages, and when modifications are attempted, additional work may surface. It is much like what happens when an older car is taken in for service, and while performing the service, the mechanic often discovers other things that need attention in order to properly complete the planned service.

The above issues require management to be flexible in planning, scheduling, and forecasting the cost for retrofit work. It is straightforward to estimate the cost of large components such as heat exchangers, pumps, motors, valves, transformers, and turbine parts, but labor, for example, is highly variable. When the emergent work is compounded with security requirements and the general logistics of working in an operating plant where there are pressurized lines and high voltage cables, productivity becomes a challenge. Safety is of the highest priority so productivity expectations often have to be adjusted to reflect the stringent safety conditions.

One of the largest challenges, however, is that much work can only be done during plant outages. For efficiency reasons, retrofit work is generally scheduled during refueling outages to avoid having the plant off line for any longer than necessary. Since refueling outages are generally 18 months apart, any perturbation in equipment delivery, engineering, licensing, or other critical activities can cause work to be significantly delayed. As a result, all stakeholders must be made aware of such possibilities and be prepared to plan for work-arounds or to reschedule the work until the next outage. Such a situation may be developing at Turkey Point due to the position of the NRC that it must address an issue, the proposed alternative source term (AST), before the uprate license application will be docketed. Consequently alternate scenarios are being discussed at FPL for rescheduling work priorities accordingly. These and many other challenges will likely occur, but they are merely management challenges. The important things are to do the work safely, minimize outage duration, and complete the project at the lowest reasonable cost and as close to the schedule objective as possible.

Q. Can you please describe the overall management challenges posed by a project such as the EPU?

A. There are at least eight salient challenges in doing major projects in operating nuclear power plants. They are:

a. Obtaining license modifications to a plant which may have been originally licensed to less stringent criteria;

b. Assuring that all work is done in a safe manner without compromise to the active steam, water, and power systems of the operating plant;

c. Working in very congested areas;

d. Coordinating work times and space with the plant operating staff;

e. Working in a security environment with double fences, multiple entry verifications, locked rooms and areas, armed security officers, and limited access points, all designed to keep the plant safe from security threats;

f. Dealing with emergent work as a result of the identification of consequential requirements from detailed engineering;

g. Accomplishing physical work within a pre-determined timeframe such as a refueling outage; and

h. The logistics of storing and moving material and locating facilities and equipment such as cranes, offices, warehouses and parking space for workers.

Q. Do cost and schedule projections often change for large projects such as the EPU?

A. Yes. There are a number of factors that affect both the cost and schedule of projects, and in most cases, the cost forecast appears to increase and the project requires more time than originally forecast. Large projects are virtually always complex, involve numerous regulatory and environmental approvals, include hundreds of drawings, thousands of components such as valves, pumps, motors, tanks, heat exchangers, and instruments, require the work of hundreds to thousands of people and take years to complete. For example, the original construction of St. Lucie Unit 2 required over 200,000 cubic yards of concrete, over 175,000 feet of pipe, over four million feet of electrical cable, over 425,000 feet of electrical conduit, and over 40,000 feet of cable tray. The quantities are the result of designing the plant to the then-current regulations, codes, and standards. The material must be specified, ordered, and once delivered to the plant site it must be properly handled and stored until needed. Final quantities cannot, however, be determined until the plant design is complete. In the case of St. Lucie 2, design continued until late into the project to address post-TMI and other NRC requirements.

While the EPU Project will not require large quantities of material such as would be required for a new plant, there a number of large components being replaced, such as the turbine rotors, the main generator rotor, selected feedwater heaters, moisture-separator re-heaters, main feedwater pumps, valves, and motors. This, as with a new plant, requires design, procurement, and proper storage on plant sites with limited space.

At the beginning of any project, adjusted historical data are all that is available to produce cost forecasts and develop schedules. Consequently, a contingency is added to the early estimates in an attempt to encompass unknown scope as well as other unknown factors. Similarly, allowances are made in early project schedules. In many cases, however, allowances can be insufficient for future unknowns, and, as a result, the project cost forecast appears to increase and the schedule becomes longer.

With respect to the EPU Project, new scope has emerged as Bechtel addresses and completes the detailed design work, and much of it is consequential. This will likely continue into the physical work (implementation) stage as well, especially at Turkey Point, since the plant is nearly 40 years old and was built to different standards. Additionally, since the EPU work is being done in operating plants, logistics add a dimension of difficulty and attendant cost which does not exist in new construction.

Section 3: Evaluation of FPL's Management of the EPU Project in 2010

Q. Have you formed an opinion with respect to FPL's management of the EPU project in 2010?

A. Yes.

Q. What is your opinion about FPL's management of the EPU project in 2010?

A. In my opinion, FPL is prudently managing the EPU project.

The generally accepted definition of "prudence" is acting "reasonably" based upon information available at the time decisions are made and actions are taken. In my experience, I have found that the 12 "Ingredients" for a successful project presented in Exhibit WBD-2 are useful tools to evaluate the reasonableness of project management's actions in various projects. These ingredients are also reflected in, and consistent with generally accepted project management standards, such as those included in the Project Management Institute's "A Guide to the Project Management Body of Knowledge." Therefore, I evaluated FPL's EPU project management by determining whether these 12 ingredients were being incorporated into the project. The FPL EPU project team is managing the project in a manner consistent with those "Ingredients" and generally accepted project management standards.

Q. On what information did you rely in forming your opinion?

A. To form my opinion on FPL's management of the EPU project, I did the following:

- I reviewed the Extended Power Uprate Project Instructions (EPPI) procedures that I considered most important to the management of the EPU Project and my review. The list of procedures, along with all other documents reviewed, is Exhibit WBD-8 to this testimony.
- I reviewed the documentation required by the procedures such as risk tables, trend reports, training records, estimates, schedules, presentations to an FPL Steering Committee, and Bechtel Metrics Reports.
- I reviewed the resumes of senior key management personnel.
- I interviewed 9 management personnel as shown in Exhibit WBD-7 to this testimony.

Q. Did you visit the Turkey Point and St. Lucie plant sites in 2010?

A. Yes. I visited both the St. Lucie and Turkey Point sites to review site facilities, speak with site management personnel, and tour plant locations where the EPU work will be performed. I was also briefed on the status of the project and plans for 2011.

Q. Do you have an opinion on the operation of the EPU site organizations?

A. Yes. Both sites appear to be well organized, are appropriately staffed, and personnel are located inside the plant security protected area. Roles and responsibilities appear to be clear and the organizations (FPL and contractors) appear to be functioning as a team. The laydown space is well organized, and there is great care in making sure that material is properly stored and handled.

Q. What is the basis of your opinion on FPL's prudence in 2010?

A. In general, I used the 12 "Ingredients for a Successful Project" found in Chart 22 of Exhibit WBD-2 as my approach for reviewing FPL's management of the EPU project. The following is a summary of my analysis of the EPU project management measured against each applicable ingredient.

1. Management Commitment

From my discussions with the FPL management, the involvement of senior management in steering committees, and the financial support for the EPU Project, it is clear that the EPU Project has full management support. I saw no indication of hesitation for FPL to do what is necessary to complete the EPU project as safely and as quickly as possible. At the same time, FPL management is also monitoring the project cost through trend, risk, and cost reports, and has commissioned independent reviews such as those conducted by Concentric Energy Advisors and myself. I believe that FPL's management is fully committed to the EPU project.

2. Financial Resources

From a review of the NextEra Energy, Inc. (NextEra) Forms 10K for 2009 and 10Q for quarter 3 of 2010 submitted to the U.S. Securities and Exchange Commission in

2010, it is clear that FPL, with the assistance provided through Florida's annual nuclear cost recovery mechanism, has a strong balance sheet, sufficient cash flow and borrowing power to finance the EPU project. FPL's financial strength has also been observed in the issuance of its debt securities. For example, in early 2009 FPL issued $500 million of first mortgage bonds, 5.96% series due April 1, 2039, which were rated "AA-". Based on the above it is clear that FPL has both the financial strength and borrowing capability to undertake projects such as the EPU project.

Based on the above it is clear that, within the current regulatory and cost recovery framework authorized by Florida law, NextEra has both the financial strength and borrowing capability to undertake projects such as the EPU project.

3. Realistic & Firm Schedule

A realistic schedule is prepared using the best information available at the time, while applying reasonable productivity rates and achievable material delivery times. That does not mean that there will not be variances in the schedule during the course of the project. As can be seen in Chart 11 in Exhibit WBD-2, even though the St. Lucie Unit 2 project was completed essentially on schedule, there were only a few weeks when the project was actually "on schedule." This was due to problems that occurred such as two labor stoppages during plant construction, the damage to the reactor auxiliary building caused by Hurricane David in 1979, the impact of the required implementation of new NRC fire protection requirements, and post-TMI requirements imposed by the NRC in 1980.

On retrofit projects such as the EPU project, however, schedule conditions are even more rigid than for new plants. This is because much work must be accomplished during scheduled plant outages. Thus, a small project challenge can result in months of delay in accomplishing the work if it cannot be completed until the next scheduled outage.

In reviewing the schedules for both Turkey Point and St. Lucie EPUs, the most significant schedule threat is the NRC approval of the License Amendment Requests (LAR). The schedules for completion of the uprates for each nuclear unit were based on historical information such as the delivery time for major components and the time required for the NRC to perform its review and issue license amendments. The NRC's actions are outside of FPL's control, and as a result the schedule could be affected if NRC approval is delayed. It is my opinion that the schedules developed by FPL for the EPU project were realistic and reasonable. However, events such as regulatory delays and consequential emergent work may require adjustments to the schedule.

4. Clear Decision Making Authority

Roles and responsibilities as well as the Juno Beach and site organizational structures on the EPU project are shown in procedure EPPI-140. Revision 9 of EPPI-140 clearly depicts the functioning of the EPU organization. EPPI-140, in conjunction with the full suite of EPPI procedures, clearly provide direction and guidance for essentially all required project functions.

I also reviewed output from the EPU organization, including schedules, EPU scope changes and forecast variances, a sample of training records, risk tables, Bechtel Metrics Reports, resumes of key personnel, and a sample of self-assessment records. Finally I discussed roles and responsibilities with several members of the EPU project team. From those discussions, I am satisfied that each member of the EPU staff was clear about their roles as well as the roles of upper management and peers.

Based on the above, it is my opinion that there is clear and appropriate decision making authority within the EPU Project.

5. Flexible Project Control Tools

When the original construction of St. Lucie Unit 2 began in 1976, the available technology was much less sophisticated than today. For example, there were no laptop computers, no internet, and little computer software was available for general use. Thus, performing computerized scheduling required a main-frame computer and was labor intensive. By the early 1980s, however, more computing technology began to emerge. This was in the form of personal computers and more software. As a result, as the St. Lucie Unit 2 project moved into the startup and punch list phases, we began to take advantage of this new technology. This was in the form of a focused startup schedule and a computerized punch list. We called this the project completion system to focus on the finishing of "punch list" work items required to complete the plant.

Today, virtually everything necessary can be done with one planning and scheduling software package such as Primavera. This is the software of choice for virtually all large projects. The selection of Primavera has afforded the EPU project the premier and most flexible project control tool available today. Instructions for developing, updating and modifying schedules are detailed in procedure EPPI-310, which also contains instructions for using the Primavera software.

The project control program for the EPU project also contains a suite of processes including:

- Interface and Variance Reporting, EPPI-150
- Time and Expense Reporting, EPPI-170
- Change Control, EPPI-300
- Forecast Variance and Trends, EPPI-301
- Cost Estimating, EPPI-320
- Risk Management, EPPI-340
- Engineering Risk Management, EPPI-345
- FPL Accrual Process, EPPI-370

I reviewed these processes as well as documents that have been created as outputs of these processes. All of the above processes are part of a package that permits management to determine its best estimate of the cost of work to be performed, identify and quantify risks, track trends and forecast resultant costs, control changes, and account for incurred costs. All of these constitute a solid project control system. Based on the comprehensive suite of project control processes employed for the EPU project and the use of Primavera software, the project control tools in use appear reasonable and meet the spirit of this "Ingredient".

6. Teamwork-Individual Commitment

Teamwork is something that I believe can best be determined by talking to project management and staff. To make such an assessment I specifically asked all persons with whom I had discussions if they thought there was teamwork on the EPU Project. Virtually everyone said there was. I also observed the interaction between the team members where possible, and there appears to be clear focus on the mission, and an understanding of the goals of the project. A team focused on the goal is an excellent ingredient for teamwork. Additionally, as recently as April 2010, FPL conducted a team building seminar. Among other things it focused on:

- Key objective is build/build upon relationships and advance issues;
- Recognize what's important to the other stakeholders;
- Identify your work behavior style, understand your strengths and weaknesses and comprehend the impact of that style on the team;
- Work on advancing issues from teambuilding interviews;
- Exchange feedback between groups on what is going well and what's missing, and how you can help;
- Engage in a discussion with our counterparts to build relations, improve communication and close gaps; and
- Develop and commit to Teamwork Behavior Absolutes.

Sessions such as this are important and reinforce FPL's commitment to foster a team relationship. Clearly, the EPU project is taking steps to assure that teamwork is in place, and from my observations it appears to be working.

7. Engineering Ahead of Construction

This ingredient was developed for a plant under construction where the owner or architect-engineer has a choice to begin construction with partially completed engineering or wait to begin construction until the design is more complete. While there are advantages of both alternatives, the latter permits a more predictable construction schedule. The St. Lucie 2 project team felt that by not beginning construction until the design was about 70% complete enabled the plant to be constructed essentially on schedule.

By operating license requirements called technical specifications, however, all modifications made to an operating nuclear power plant must be presented to an on-site review committee for approval. This is a process called a Plant Change and Modification (PCM). Thus, the design must be complete at that time. For the EPU project, the engineering required to get to the PCM is complex and in many cases requires a plant walk-down to verify the as-built condition of the plant. As a result, the engineering frequently is the critical path activity. For the EPU, each outage can be considered its own project, and all the design engineering is occurring before construction that occurs for that particular outage. As a result, FPL is in fact performing the necessary engineering before construction, despite the overlapping nature of the work on various units during various outages. In my opinion, this appears to be a reasonable way to complete necessary design engineering prior to construction, while at the same time completing the overall EPU project as soon as practicable.

8. Early Startup Involvement

Testing for the EPU project is delineated in procedure EPPI-445 issued on April 23, 2009. The issue date was approximately two years prior to EPU testing activity. As is stated in EPPI-445: The purpose of this procedure is to identify testing responsibilities for the EPU project and to delineate responsibility between FPL and the EPU engineering, procurement, and construction contractor. The testing responsibilities include preparing post modification test plans for modification packages, preparing new and/or revise existing test procedures for construction tests, pre-operational tests and start-up/power ascension tests; performing construction tests, post modification tests, and power ascension tests for the EPU projects. These activities are shared between FPL and the EPU contractor within the scope of their respective contract agreements. The procedure goes on to establish responsibilities, precautions, instructions and record requirements.

To implement this procedure a startup organization was established at both Turkey Point and St. Lucie in 2009. The organizations consist of a Manager supported by a staff of engineers, coordinators, and planners. Based on a review of procedure EPPI-445, the established organizational structure, discussions with the EPU site project managers, and FPL's responsibility under the requirements of its NRC operating licenses, it is my opinion that the startup requirements for the EPU project are well understood and have been implemented in a timely manner.

9. Organizational Flexibility

During the construction of St. Lucie Unit 2, the organization was continually re-aligned to emphasize the necessary leadership as the project passed from phase to phase. For example, at the beginning of the project, engineering and licensing were the primary activities. After the construction permit was received in June 1977, the project focus was the site construction organization. Later in the construction phase as the plant became nearly completed, the startup organization took the lead. A second licensing organization was formed to address post-TMI NRC regulatory requirements (see Chart 18 in Exhibit WBD-2). It is appropriate – indeed necessary – to be flexible and adjust the organization to the current needs of the project.

FPL made such an adjustment in 2009 as the project moved away from the conceptual phase into the production phase. More authority is now vested in the site manager, and functions such as engineering, licensing, and procurement were moved to the sites. All contractors now report to the site manager or his designee. As the projects move through construction and into startup and testing focus will again shift. As modifications are completed, staff will be reduced since early project functions such as engineering and licensing will no longer be required to the degree as they are now. Ultimately, as the projects wind down and records are completed, contractor staff will be reduced and FPL staff will be given new assignments. This is a typical cycle for all projects.

Contrary to an operating business or an operating power plant, from the day a project begins, all members of the project team begin to work themselves out of a job. However, most project people enjoy being part of a team that creates something. On a parcel of vacant land a power plant, a chemical plant, a skyscraper, or a major highway system takes shape. As that happens, most project people that I know feel like part of them becomes part of the project.

Based on my observation and interviews with the members of the EPU management team, I believe they are prepared for such future adjustments. As a result, it is my opinion that organizational flexibility is built into the EPU project philosophy.

10. Ongoing Critique of the Project

FPL has had the EPU project reviewed by several independent organizations, including the FPL quality assurance organization as required by 10 CFR 50 Appendix B, Concentric Energy Advisors, the FPL Internal Audit Department (Jefferson

Wells), the Florida Public Service Commission Audit Staff, and myself. FPL has also utilized outside resources such as High Bridge Associates, to perform an independent check on cost estimates for particular scopes of work. Additionally, procedure EPPI-380 requires formal self-assessments, and procedure EPPI-340 defines the EPU risk management program. While the latter two are not independent, they require a critical review and a formal evaluation of possible future risks to the project. As indicated above, I have reviewed self assessment documentation and risk tables. In total, these critiques represent a comprehensive critical view of the project.

Based on the above, the EPU project critiques are consistent with this "Ingredient".

11. Bethesda Office for Licensing

This Ingredient is not applicable to the EPU project. FPL established an office in Bethesda in 1981 to expedite the communication between FPL and the NRC during the NRC's review of the license application for St. Lucie Unit 2. Today, with the internet and the ability to electronically transfer files, such an office would not have the same benefit as in 1981.

12. Owner Takes the Lead

With both the St. Lucie and Turkey Point plants being NRC licensed operating facilities, FPL has the responsibility to protect the health and safety of the public as an overarching requirement in its NRC licenses. Also, the operation of each plant is governed by technical specifications approved by the NRC. This mandates that FPL be the lead on any work done in the plant. In the case of the EPU project, a separate organization was established to manage the integration of the engineering, procurement, construction, and testing. All contractors working on the EPU project report to the FPL site organization. The final approval to perform the work, however, resides with the Plant Manager of each plant. Accordingly, this "Ingredient" is clearly in place on the EPU project.

Q. Did you review any other aspects of the EPU project?

A. Yes. I reviewed FPL's vendor management, the execution of the EPU work during the one refueling outage in 2010, and preparations for two refueling outages in 2011.

Q. Please comment on FPL's EPC vendor management.

A. While there are many vendors employed on the EPU project, Bechtel has the largest scope for which there is the most risk remaining. For example, at St. Lucie the total forecast EPU cost was $916 million as of year-end 2010, of which about a third has been spent, another third involves work which has a well defined scope which includes FPL's in house cost and/or involves a fixed price contract such as major components resulting in low risk, and the remaining third is in Bechtel's engineering-procurement-construction (EPC) scope with the most risk. Thus management's attention should be and is focused on assuring that the work being performed by Bechtel meets the project's quality, cost and schedule objectives. The scope of work for both Bechtel and FPL is defined in a unique specification for each plant. Each specification describes in detail general information, project management, design engineering/licensing, construction/implementation, procurement, project controls, quality assurance/quality control, radiation protection, maintenance and operation of equipment, temporary services, and safety and security services. Each specification also provides references to applicable codes and standards and defines applicable technical terms.

In reviewing the specifications I found that they are clear and sufficiently detailed to reasonably assure that both Bechtel's and FPL's responsibilities are clearly defined. These specifications are also consistent with other such documents with which I am familiar.

I then reviewed the process employed for management of the Bechtel contract. It is very straight forward, provides good control and supports the "owner takes the lead" ingredient. Bechtel cannot perform any work without FPL's approval. The process begins with Bechtel submitting a scope form to FPL. FPL reviews the proposed work and negotiates the task. Once agreement is reached the task (job) is added to the EPU forecast and metrics. The new job is then added to the project control system and is tracked by Bechtel in its metrics report which is sent to FPL weekly. The Bechtel metrics report tracks each job by discipline earned hours and status. The Bechtel metrics report tracks and displays status, productivity, and cost performance. The approved job is also put into the Primavera scheduling system and is tracked by FPL. All jobs are tracked on an hourly basis during outages.

Based on my review, FPL is managing the Bechtel contract in a sound manner.

Q. Please comment on the execution of the fall 2010 outage.

A. EPU modifications were made at Turkey Point Unit 3 during a planned outage known as 3R25 which began on September 25, 2010.

Eleven EPU modifications were planned to be completed during the outage, but due to a variety of factors two modifications were deferred until the next refueling outage, 3R26, and the scope was reduced on four others. According to FPL the estimated cost for the modifications was $20.9 million and the actual cost was $18.7 million. Even though some cost reduction was due to deferrals and scope reduction, the overall performance appears to have been quite good.

More details on the Turkey Point outages can be found in Exhibit WBD-11.

Q. Please comment on the preparations that were underway for the 2011 outages.

A. Two outages are planned for 2011. As of year-end 2010, outage 2-20 was scheduled to begin on January 3, 2011 at St. Lucie 2 and outage 4R26 was scheduled to begin for Turkey Point 4 on March 19, 2011.

At Turkey Point, fourteen modifications are planned for which eleven PCM packages were issued prior to January 2011. The material required for the modifications is either on site or scheduled for delivery well in advance of the outage date. The EPU scope of work for outage 4R26 can be seen in Exhibit WBD-11.

I toured the Turkey Point plant on December 1, 2010 with the EPU Site Director and Senior Project Manager. On the tour I was shown the modifications planned for each unit, and which modifications were being planned for the March 2011 outage. From the tour and explanations of planned work, it was clear that the site EPU management is organized, the mission is clear, and the team is focused on meeting the EPU goals. Based on what I have seen, I believe the site organization has done an excellent job of planning and preparing for outage 4R26.

At St. Lucie, outage 2-20 was scheduled to begin on January 3, 2011 and included the EPU scope of work shown in Exhibit WBD-12. The outage was planned to be completed on March 9, 2011. This outage is significant in that it includes major modifications such as main transformer replacement, rewinding the main generator, main generator rotor replacement, low pressure turbine rotor replacement, and condensate pump replacement. It is estimated that an additional 20 megawatts will be realized from the modifications in outage 2-20 even without increasing reactor power, due to efficiencies gained. The forecast cost for the EPU modifications in outage 2-20 was $75.5 million.

I toured the St. Lucie plant with the EPU Site Director on November 30, 2010. During the tour I saw a very organized EPU operation with good use of the space to the south of the plant. Additionally, much preparatory work was ongoing in the plant in preparation for the January 3, 2011 commencement of the outage. Figure 11 shows photographs of the site laydown area as well as the organization of work areas in the plant. As can be seen the EPU project at St. Lucie is well organized and well prepared for the January 3, 2011 outage.

Q. What is your conclusion regarding FPL's EPU Project management?

A. Based upon my review of relevant controls, procedures, business documents, and my interviews with various project personnel, my conclusion is that FPL prudently managed the EPU project in 2010. Overall, FPL is employing the "Ingredients" for a successful project, which in my experience are good indicators that that project is being reasonably managed. This conclusion is supported by the successful outage work that occurred in 2010 and that appeared to be underway for 2011.

Q. Does this conclude your testimony?

A. Yes.

WBD-1

WILLIAM B. DERRICKSON

EXPERIENCE HIGHLIGHTS

Over forty-six years of engineering and management in the nuclear power and utility industries and on government projects, including construction of new facilities, major modifications to existing plants, design, startup, overall project management, and providing consultation and expert witness services.

PROFESSIONAL EXPERIENCE

1986-Present **WPD ASSOCIATES, INC.**, Austin, Texas

WPD Associates specializes in Executive Consulting and Expert Witness support.

Current assignments include:

- Expert witness for a non-U.S. utility in a nuclear related international arbitration (2006-present)
- Advisor on risk and project management issues to a major consulting firm advising U.S. utilities regarding initiating nuclear projects (2007 to present)

Other executive consulting and/or expert witness assignments have included:

- Nuclear Advisor to the Board of Directors, Tennessee Valley Authority, Knoxville, Tennessee (1986-1988)
- Expert Witness in the Diablo Canyon Nuclear Plant rate case for Pacific Gas and Electric Company, San Francisco, California (1986-1988)
- Expert Witness in the international arbitration between Westinghouse and the Philippine government concerning the operability of the nuclear power plant built by Westinghouse on the Batton Peninsula for Westinghouse Electric Corporation, Pittsburgh, Pennsylvania (1991-1994)
- Expert Witness for the owners of the Alaska Pipeline in a rate case (1996)
- Expert Witness for a major U.S. electric utility regarding what components of a nuclear plant constitute pollution control equipment (1998)
- Expert Witness for a major architect engineer in approximately twenty asbestos cases (2001-2010)
- Member of an external review team for DOE on the Waste Treatment Project in Hanford, WA. The mission was to evaluate the Bechtel cost estimate for the project (2005-2006)
- Led an independent review team for the Vermont Electric Light Co. (VELCO) to oversee approximately $500 million of transmission lines and substation projects (2005-2006)

1995-2009 **IBEX ENGINEERING SERVICES,** Palm City, Florida
Chairman and CEO. IBEX Engineering specializes in general staff support, primarily to the energy industry.

1993-1995 **QES, INC.**, Stuart, Florida
Chairman of the Board, Chief Executive Officer. QES, an engineering and consulting company chartered in December 1993, was formerly the Energy Services Division of Quadrex Corporation and provided specialty engineering and consulting services to the energy industry.

1988-1993 **QUADREX CORPORATION**, Gainesville, Florida
Chairman of the Board, Chief Executive Officer effective February 1, 1989.
President and Chief Operating Officer since February 1, 1988. During this period, repositioned the company within the nuclear power industry and led development of the environmental business area.

1985-1988 **NEW HAMPSHIRE YANKEE ELECTRIC COMPANY**, Seabrook, NH
President. Responsible for all activities (construction, quality assurance, employee relations, purchasing, licensing, operations and startup) related to construction and operation of the Seabrook Nuclear Station, an 1150 megawatt pressurized water reactor plant.

1970-1984 **FLORIDA POWER AND LIGHT Co.**, Juno Beach, Florida
Director of Projects. Responsible for all FP&L major power plant capital projects and project services which included cost and schedule control and estimating.

Project General Manager responsible for management of all phases of St. Lucie Unit 2 Project, an 800 megawatt, pressurized water, nuclear power plant completed in six years at a cost of $1,420,000,000. This responsibility encompassed planning and scheduling, engineering, procurement of material, construction, licensing and startup.

Also responsible for St. Lucie Unit 1 (a duplicate of St. Lucie Unit 2) retrofit program. This effort supported the operating plant by supplementing the plant maintenance group and making capital improvements and additions. The organization consisted of purchasing, engineering, licensing, planning, scheduling, and construction personnel.

Other positions and responsibilities while at Florida Power and Light Company include major modifications at the Turkey Point Nuclear Plant, Assistant Project General Manager for the St. Lucie Unit 1 Project, Superintendent of Nuclear Construction, Project Construction Supervisor, Startup Coordinator at Turkey Point and Electrical Startup Engineer.

1969-1970 **SUN SHIPBUILDING AND DRY-DOCK COMPANY**, Chester, Pennsylvania
Instrumentation Engineer responsible for research and development of instrumentation systems for shipboard use.

1968-1969 **HERCULES, INCORPORATED**, Wilmington, Delaware
Responsible for design, installation and startup of instrumentation and control systems in chemical plants. These were primarily electronic analog and digital systems. Participated in five projects: one research and development, three startups and one from design through startup. These plants produced polypropylene, film, tall oil, nitric acid and flocculants.

1964-1968 **DELMARVA POWER AND LIGHT COMPANY**, Salisbury, Maryland
Supervisor of Electrical Maintenance responsible for maintenance of electrical systems at the Vienna, Maryland and Indian River, Delaware power plants. The plants consisted of pulverized coal fired units of various sizes, diesels and gas turbines. Duties included supervising plant electricians and contractors for maintenance of plant equipment and for installation of planned modifications.

EDUCATION

BS, Electrical Engineering, minor Political Science, Univ. of Delaware, Newark
Program for Management Development (PMD) 38, Harvard Business School, Boston, Massachusetts

Extended Studies Include:

Graduate work in Electrical Engineering and Business Administration, University of Delaware, Newark, Delaware
Federal Government Operation, Brookings Institution, Washington, D.C.
P.U.R. Guide- a one year course in the operation and management of public utilities
Sales Analysis Institute
Kepner-Tregoe Decision Analysis
Managerial Grid
Financial Analysis
Management by Objectives
Telos- Determination of Group and Individual Decisions
Managing Management Time

PROFESSIONAL AND CIVIC AFFILIATIONS

Present: American Nuclear Society
Project Management Institute

Past: New Hampshire Governor's Roundtable
Atomic Industrial Forum Subcommittee
Institute of Electrical and Electronic Engineers
American Society of Mechanical Engineers

PAPERS AND PUBLICATIONS

"A Nuclear Plant Built on Schedule" presented at the Project Management Institute Symposium/Seminar, Houston, Texas, October 17-19, 1983.

"Managing Large Complex Projects" presented at the annual meeting of the American Society for Macro Engineering, Washington, D.C., February, 1986.

"A Nuclear Plant Built on Schedule in the United States-Lessons for the 1990's" presented at the International Atomic Agency's Conference on Nuclear Power Performance and Safety, Vienna, Austria, September, 1987.

"Achieving Project Goals in Contrasting Environments; The Value of a Strong Management Philosophy", Co-authored with George B. Bradshaw, presented at the Project Management Institute annual meeting in Milwaukee, Wisconsin, October, 1987.

AWARDS AND RECOGNITION

"Construction Man of the Year" awarded by McGraw-Hill/Engineering News Record magazine in February, 1984, for proving that a nuclear plant can be built in six years.

Listed in Who's Who in America
Listed in Who's Who in the World
Listed in Who's Who in Finance and Industry

Listed in Who's Who in Science and Engineering

WBD-2

ST. LUCIE UNIT 2
A NUCLEAR PLANT BUILT ON SCHEDULE

ABSTRACT

Florida Power & Light Company currently has four nuclear units in operation with St. Lucie Unit 2 being the last to receive an operating license in June. It's sister Unit 1 received its license in 1976 and has, through 1982, compiled one of the best operating records in the United States.

The full power license for St. Lucie Unit 2 was received from the Nuclear Regulatory Commission (NRC) on June 10, 1983, just six years after construction began. The industry average for construction of nuclear plants in this time period is about 10 years.

During the course of the project we were constantly on or near our schedule and always ahead of industry averages.

This was done despite issuance of numerous regulations by the NRC (TMI), a 1979 hurricane which did considerable damage to the Reactor Auxiliary Building, labor problems and an NRC schedule review team that determined the best we could do was to complete the plant a year later.

The final price tag is about $1.42 billion, including AFUDC.

In operation to date the post core loading test program has been completed in less than two months, enabling us to put the plant into commercial operation only two months after its original scheduled date of May 28, 1983!

ST. LUCIE UNIT 2
A NUCLEAR PLANT BUILT ON SCHEDULE

by:

W. B. Derrickson
Director of Projects
Florida Power & Light Company

Prepared for:

Project Management Institute
1983 Seminar/Symposium
October 17-19, 1983
Houston, Texas

CONTENTS

INTRODUCTION

Since the mid 70's when nuclear power was the "energy source of the future" everything has seemed to go wrong for the ailing industry. From quality problems to financial problems, the entire industry has been shaken in one way or another. There have been no orders for nuclear plants in the USA since the mid 70's.

Florida Power & Light Company currently has four nuclear units in operation with St. Lucie Unit 2 being the last to receive an operating license in June. Its sister Unit 1 received its license in 1976 and has, through 1982, compiled one of the best operating records in the United States.

The early days of Unit 2 were plagued with much of the same confusion and regulatory hassle that other units have experienced but upon receipt of the construction permit in June 1977, utilizing FPL and Ebasco experience gained during the construction and startup of Unit 1, we were poised to attack the new project in a way that has enabled us to meet our objectives and complete the plant on schedule.

In the following pages we describe what was accomplished and how it was done utilizing a highly skilled project team with excellent tools, motivated to reach their goal.

WHAT WAS ACCOMPLISHED

The full power license for St. Lucie Unit 2 was received from the Nuclear Regulatory Commission (NRC) on June 10, 1983, just six years after construction began. (Charts 1 & 2) The industry average for construction of nuclear plants in this time period is about 10 years. (Chart 3)

During the course of the project we were constantly on or near our schedule and always ahead of industry averages. (Charts 4 & 5)

This was done despite issuance of numerous regulations by the NRC (TMI), a 1979 hurricane which did considerable damage to the Reactor Auxiliary Building, labor problems and an NRC schedule review team that determined the best we could do was to complete the plant a year later.

The final price tag is about $1.42 billion, including AFUDC. Many plants completed in this time frame are in the $2-5 billion range. By completing the plant on schedule our customers additionally benefit from the lower cost of nuclear fuel now. St. Lucie Unit 2 displaces about eight million barrels of imported oil annually.

In addition to the cost and schedule achievements, the performance of the plant operation to date indicates a quality technical effort as well. The Hot Functional Test, for example was completed in 27 days vs. an average of some two months for other plants. The fuel was loaded into the core in less than four days vs. an industry average of 8 to 10 days.

In operation to date the post core loading test program has been completed in less than two months, enabling us to put the plant into commercial operation only two months after its original scheduled date of May 28, 1983!

HOW IT WAS ACCOMPLISHED

HISTORY

Originally, construction of both St. Lucie 1 and 2 was planned to proceed concurrently, but then FPL decided to delay construction of the second unit due to a reduced load forecast. St. Lucie 1 started with construction forces moving on site in late March 1969. The Atomic Energy Commission, issued the construction permit on June 30, 1970, and first concrete placement for the Reactor Containment Building took place a week later. Installation of the nuclear steam supply system began in September 1973 and core loading in March 1976. St. Lucie 1 began commercial operation in December 1976.

Work began on St. Lucie 2 in 1971, with initial efforts directed toward preparing the Preliminary Safety Analysis Report (PSAR), Environmental Report and antitrust information required by the NRC before construction start. Although the PSAR was submitted for review in April, 1973 (Chart 6), subsequent meetings and site visits were conducted with the NRC staff to resolve such questions as site characteristics, radiological assessment, hydrology, geology and seismology. Other discussions probed emergency planning, industrial security and design features of the nuclear power plant. In response to these requests and discussions, an additional 44 amendments were eventually docketed to the PSAR.

The NRC issued its Safety Evaluation Report in November 1974, and in March 1975 awarded the Limited Work Authorization. Construction work started in June 1976, after receiving State Site Certification and was limited to excavation and foundation work up to existing grade level.

Four months later, however, construction work ceased and the work force was laid off. A regulation specified that the NRC must study a number of potential sites before allowing any work to begin, whereas the staff of the licensing board had studied a hypothetical alternative to the St. Lucie site. After various appeals and site hearings, the NRC eventually granted a construction permit in May 1977, but not before $60 million was added to the construction cost as a result of the work stoppage.

MANAGEMENT COMMITMENT

In the early stages of the project, FPL established a project management organization to direct, inspect, survey, monitor and audit the performance of all services performed by FPL contractor personnel and/or any subcontractors (Chart 7). This organization is the contact with FPL on all contract-related matters and has the right of approval of all services and work performed.

A project general manager, through a project team organization, is FPL's designated representative having the responsibility and authority for the total management of the project..

In 1977, completion of St. Lucie 2 on schedule and within budget became one of FPL's corporate objectives. Thus, through the Management By Objectives Program all department objectives were required to support the project.

Project objectives were established annually to support completion of the project on schedule and within budget. Results were reported to management semi-annually and Corporate Management assistance was provided when required.

PROJECT PLANNING & SCHEDULING

During the period October 1976 to March 1977, a team of construction supervisors under FPL direction, developed what was to become the Project Master Schedule. A 65-month schedule for the project (start of concrete to start of fuel loading) was established and major milestones were identified and fixed. This set the stage for all future planning. This schedule consisted of an integrated engineering and construction plan and included summary start-up logic.

The schedule philosophy adopted by the project was two fold: 1) Implement five levels of control and schedule development, and 2) maintain key schedule indicators of project status.

A brief description of the five levels of schedule control can be seen in Chart 8.

Level I - Milestone Schedule was developed by discipline by building. Approximately 200 activities were used to describe the total project with time indicated in months. It was updated quarterly for upper level management information.

Level II - The Master Project Schedule was broken down by system, building and area. Its purpose was to establish basic interfaces and schedule parameters at a lower level of detail. The Level II integrated project schedule had approximately 20,000 activities, including 10,000 construction activities.

Level III - The detailed construction schedule. It depicted the way the project was to be actually carried out and monitored to the most current information. The Level III breakdown was by building, elevation and cubic and included approximately 32,000 activities in total. Since it was developed on a yearly look ahead, it replaced the old Level II logic.

Level IV - The work package level. It was a detailed planning tool designed to capture all work within a predefined cubic. Fragnets were developed to emphasize logic and construction sequencing. These manual fragnets were then rolled up to form the Level III computer schedule. Work packages also included bills and material and late material and engineering items.

Level V - (Two Week Look Ahead) was a manual bar chart reflecting daily work schedules over a rolling two week window. It was used for short internal scheduling, manpower leveling and requisitioning material from stores.

The second half of our scheduling philosophy was the use of indicators, i.e., control tools. An overview of most of our control tools and the timing of their implementation can be seen in Chart 9. A few of the more visible indicators were productivity, schedule variance, physical accomplishment and bulk quantity tables.

Physical accomplishment was primarily developed through our cost reports and portrayed the percent complete of construction. (Chart 10) They were implemented for each major area (building) and total project and updated monthly. The percent complete was established by using actual craft manhours expended based on installed quantities. An example would be reporting concrete complete the day it was placed.

Schedule variance was tracked using the construction critical path as shown in Chart 11. Each month the Level III computer schedule was statused, run, and analyzed to produce the monthly schedule variance. With the fuel load date maintained at October 28, 1982, the critical path varied from a high of 15 weeks ahead of schedule to a low of 21 weeks behind schedule, due to the various major events as shown.

Productivity was used as an indicator both weekly and monthly to identify site management problem areas requiring corrective action. (Chart 12) Causes of poor productivity were analyzed and corrected to avoid major schedule impacts and cost overruns.

Constant reporting of installed and forecasted quantity information, provided management with an excellent trending tool to measure performance against estimated as well as against other nuclear site quantity performance. (Chart 13)

Special priority was placed on engineering, design and delivery of piping and hangers. These were scheduled for delivery a full 18 months prior to the "early start" dates. The result was that hanger installation preceded pipe erection and minimized the need for temporary pipe support devices to a large degree. This resulted in an orderly pipe installation program.

Although uncertainty existed about St. Lucie 2's future when the limited work authorization was withdrawn in October 1976, a decision was made to continue in accordance with previously established engineering, design and procurement schedules. As a result, when the construction permit was granted in May 1977, approximately 75 percent of the original scope of engineering and design was completed and 40 percent of the engineered materials were delivered. In retrospect, this decision typified the total commitment and support this project has received from its inception from FPL's executive management.

Another factor which contributed to the success of the construction effort at St. Lucie 2 was a detailed review of the design from St. Lucie 1. The objective of this review was to recommend areas where design enhancements could be made to improve construction productivity and costs. As a result, approximately 250 items were addressed and incorporated into the design. In addition, a Design Problem Review (DPR) program was initiated. This was a comprehensive review by engineering of all St. Lucie 1 changes, i.e., backfit changes, operating plant enhancements, regulatory requirements, etc., in order to ensure their consideration and disposition for St. Lucie 2. Over 1,000 items were considered with approximately 350 incorporated into the St. Lucie 2 design.

CONSTRUCTION SITE ORGANIZATION

The construction site organization utilized an integrated approach which has proved quite effective (Chart 14). It consisted of both FPL and Ebasco personnel integrated into one organization. In this organization, Ebasco's supervisory construction staff, under the overall direction of the FPL site manager, managed and directed construction activities of craft work forces and subcontractors according to the schedules established. The organizational functions which FPL wanted to influence directly were under FPL supervisors, reporting to the Site Manager. These functions included quality control and quality assurance; construction cost control, planning and scheduling; and support services, such as area stores, site purchasing, contract and office administration.

Construction Site Management

There have been many major productivity and quality improvement efforts utilized in the construction effort. (Chart 15) Since 1978, St. Lucie Unit 2 maintained through the Methods group of Plant Construction a periodic work sampling program including crafts and equipment utilization. St. Lucie Unit 2 showed a 37% increase in direct work and well exceeded the national average in four of the six samples.

Operation analysis of areas such as steel erection, condenser tubing, pipe and hanger welding and cable pulling were also performed. Some work operations improved as much as 50%.

Time lapse photography was used on over 20 work operations and significant results were obtained. As an example, the condenser tubing production was doubled using the same manpower.

Management Assessment of Performance and Quality (MAPQ)

To enhance the ongoing quality improvement program at St. Lucie Unit 2 MAPQ was used in the following manner:

a) Design and administer two survey instruments to top management involved in the project to determine the project objectives and possible indicators for these objectives. (Chart 16)

b) Interview Key personnel to determine other performance and quality indicators needed and to develop goals or targets for each objective.

c) Have coordinated program that includes both Methods Group (Studies and Work Sampling) and Management Services activities that maximize productivity efforts.

d) Establish Management by Objective/Indicator Charts with past data and future goals.

e) Assign one individual responsible for progress of each chart and have a management review system in place using Management-By-Exception Principles.

f) Accomplish studies of problem areas and present findings to the Site Manager, PGM and the site Quality Review Board.

START-UP PLANNING AND IMPLEMENTATION

One of the major contributing factors in the completion of St. Lucie 2 nearly on schedule has been the ability to turn over components and systems to our operating department in an orderly and timely manner. The success of this phase of the project was due to the early planning scheduling and implementation of a start-up program, and probably more importantly to FPL's overall philosophy concerning acceptance and testing of equipment and systems.

This overall philosophy had as its primary objective the earliest possible acceptance of equipment, components and partial systems, in order to enable early testing and problem identification.

First, we developed an overall start-up program plan and schedule which required early on-site presence of operating department personnel 35 months prior to the scheduled "start of fuel load" date. This was not just a token work force, but rather a sizable commitment of manpower numbering approximately 64 people. Their early work consisted of a number of tasks, the highlights being to:

a) Define start-up system boundaries.

b) Prepare preoperation test procedures.

c) Establish construction turnover sequence.

d) Establish preoperational test requirements.

e) Determine start-up (construction and operations) manpower levels.

f) Establish target milestone dates.

Construction/Start-up Schedule Integration

The detailed start-up schedule and logic was then integrated with the construction schedule to develop one combined schedule that the jobsite worked to and engineering and design supported.

Implementation

With the establishment of the target milestones for start-up, the "SCAT" Program (Start-up/ Construction Accelerated Turnover Program) was initiated to expedite the turnover of systems from construction to operations. Essentially, this program identified portions of total systems PTO's (Partial Turnovers) which are then completed and turned over to Operations, allowing early testing and problem identification of system components. Approximately 488 "packages" were identified and scheduled for turnover in priority sequence to support established start-up milestones. In addition, a computerized listing of all system components was developed and used by the construction test group to "punchlist" the systems for completeness. In addition, to the PTO's, CTO's (Conditional Turnovers) were also established, whereby operations accepted systems on a conditional basis, with an agreed upon list of exceptions, but sufficiently complete such that testing and checkout could proceed. Again, this was in keeping with the start-up philosophy, by which early acceptance of components and partial systems enabled sufficient time to identify and resolve equipment and start-up test performance problems with minimal impact to the overall scheduled core load objective for the project.

In the course of the start-up phase of the project, the construction organization objectives gradually shifted from a bulk quantity installation effort and area concept of control to total support of start-up turnover requirements and work performed on discipline basis.

ONGOING CRITIQUE OF THE PROJECT

Many times during the life of the project, independent groups were brought in to review various facets to ensure the project team was not overlooking problems. For example:

a) FPL-QA Department checked all areas.

b) Quality Task Force reviewed the project QA/QC program.

c) Independent Engineering Verification Task Force evaluated the adequacy of the design and translation of design to field installation.

d) Bechtel Power Corp. checked the welding program.

e) Southwest Research Institute monitored Welding QC.

f) Quadrex Corp. reviewed the Containment Cooling System.

g) Bechtel Power Corp. studied the plant AC Electrical Systems.

h) EDS reviewed the Containment Spray System.

i) Theodore Barry & Associates audited the Project Management Organization.

j) Schedule Task Force continually reviewed the Project Schedule.

These teams operated on a task basis and reported results to the project team for review and corrective action if necessary.

EXAMPLES

REACTOR AUXILIARY BUILDING "STAIR STEPPING" CONCEPT

One of the innovative ideas that went into the initial plan and schedule was the "stair stepping" concept for the construction of the Reactor Auxiliary Building. In this plan, the building was constructed with emphasis placed on early completion of the west end of the building. The philosophy being that early completion of this end of the structure provided an early start to installation of the more critical areas of equipment installation in the reactor auxiliary building; i.e., the control room and the reactor auxiliary control boards, the cable vault area, and NSSS auxiliary equipment.

As a result, the building during construction took on a "stair step" appearance, and as each elevation was completed, all major equipment and appurtenances were moved into that level prior to the roof being installed. Considerable amount of Q deck construction was also utilized in an effort to minimize forming and shoring requirements. The net result was that critical areas were completed earlier and key crafts could start their work sooner.

REACTOR CONTAINMENT BUILDING

Foundation design considerations were finalized when plans called for both St. Lucie 1 and 2 to be built simultaneously. Subsurface exploration borings indicated poorly consolidated sand with thin layers of clay to a depth of 65 feet below existing grade. To meet seismic criteria, a plant island was constructed by excavating the unsuitable material, back-filling with well-graded sand and then compacting to required specifications. This plant island resulted in a compacted Class I fill measuring 780 by 920 feet and 78½ feet deep. The plant island was sized as small as possible by spacing the plant structures at minimum distances apart. When we decided to delay construction of St. Lucie 2, these plans were technically feasible, but subsequently they did require unique design and construction efforts for the second unit.

One of these special provisions, we believe, was the first nuclear safety Class 1 cofferdam ever to be engineered and constructed. It was necessary to protect the safe shutdown ability of St. Lucie 1 under all foreseeable circumstances, including earthquakes.

A circular sheetpile cofferdam for the reactor containment building was braced with internal compression beams and sized to allow excavation, concreting of the base mat and walls up-to-grade elevation, and subsequent back-fill operations.

The 180 foot diameter circular cofferdam was constructed by driving 500 tons of sheetpiling in 72-foot lengths through compacted sand with electrical vibratory hammers. The 900 tons of horizontal bracing (walers) consisted of wide-flange beams 36 inches deep and weighing 230 pounds to the foot, installed every five feet on vertical centers. To allow dewatering of the cofferdam, 18 deep wells were installed along the periphery. Driving of the sheeting started in June 1976, and the mudmat (working surface) was placed in late September of that year.

SLIPFORMING

Another innovative construction accomplishment at St. Lucie 2 was the "slipforming" of the concrete containment shield wall for the reactor containment building, in lieu of the traditional "jump" method. This concrete cylinder has a three-foot-thick reinforced wall, approximately 190 feet high with an inside radius of 74 feet. It is supported by a ring wall (9 feet thick and 4 feet high) which, in turn, rests on a 10 foot thick base mat. The shield wall contains more than 1000 tons of reinforcing steel with another 23 tons of embedded materials such as electrical conduits, grounding cables and anchor bolts.

Wall placement through slipforming of 10,000 cubic yards of concrete averaged 11-1/2 feet per day, and the operation took place without interruption in only 16-1/2 days in November 1977. Manpower for slipforming averaged 398 craft workers, and the crafts worked three shifts a day, seven days a week until completion. Immediately after completion of slipforming, construction on the steel containment vessel started inside the shield building.

HURRICANE DAVID

When the project was 26 percent completed, a severe storm seriously jeopardized our ability to meet objectives and be ready for start of fuel load in November 1982. The high winds of Hurricane David struck (on September 3, 1979) toppling a 150 ton construction derrick being used to supply materials into both the Reactor Containment Building and the Reactor Auxiliary Building. The storm completely destroyed the derrick, composed of a 180 foot tower with a 256 foot mast resting on top of the tower, and a 200 foot boom. More importantly, the falling derrick severely damaged the Reactor Auxiliary Building under initial construction. Lost schedule time to repair the damage and replace equipment was estimated at 13 weeks.

Immediately engineering and construction supervisors formulated recovery plans. A task force of construction and site engineering personnel pinpointed all damage on design drawings. Engineers assessed this damage, developed repair procedures and determined the extent of necessary nondestructive testing of adjoining areas. Concurrently, equipment damage was reviewed with vendor representatives and orders were expedited for replacement equipment. Construction plans called for additional overtime of crafts and construction supervisors to make up the additional hours required for repairs. As the recovery operation proceeded, site activity unaffected by the derrick collapse maintained its previous schedule.

NSSS INSTALLATION

An important benchmark in the NRC's assessment of nuclear plant construction is the installation of the nuclear steam supply system's major equipment, i.e., reactor vessel, steam generators and pressurizer. The Project was able to meet this milestone on a progressive schedule by adopting two innovative ideas.

First was early planning and the decision to erect the containment steel vessel utilizing the "tops-off" approach. Basically, this method provides post weld heat treatment of the vessel before setting the dome. Because of thinner plates the dome did not require heat treatment and could be erected at a later time. As a result, interior concrete work started months earlier than otherwise possible and ensured that support structures were ready for NSSS installation.

Secondly, the interior concrete was not brought up to the operating level before setting the nuclear vessel. Instead, engineering and construction personnel, in conjunction with the heavy rigging subcontractor and the polar crane manufacturer, simplified the "posting" arrangement for utilizing the polar crane in setting the vessels. Using a two-shore (instead of six-shore) polar crane girder support system saved considerable schedule time and enabled construction forces to meet the target date of June-July 1980

FSAR PREPARATION AND REVIEW CYCLE BY THE NRC

A significant threat to the project schedule occurred in 1980 during the Nuclear Regulatory Commission's caseload forecast panel review of the site and project schedule. The NRC estimate of project completion generally follows a statistical schedule model shown in Chart 17. This model was developed prior to TMI and includes three curves showing the lower, medium and upper quartile. Using the model and other data obtained during their on-site visit in February and September of 1980, the NRC projected a fuel load date of December 1983, which was 13 months later than that established by the project. Since the NRC schedule for review of the Final Safety Analysis Report (FSAR) was based on this later date, it was necessary to convince them that the Project would meet our schedule. Through concerted FPL upper management efforts, the NRC accepted the project schedule and completed the FSAR review in a record time of 9 months.

The plan developed for the project called for the preparation of what was designated as the Design Defense/FSAR Interface Document. A well known problem in meeting nuclear power plant schedules is the "Ratcheting" that occurs during the licensing review cycle and results in additional unforeseen additions to the project scope and an increase in schedule. To minimize that from occurring on St. Lucie 2, a documented Three Party Review (Ebasco, FPL & Combustion Engineering) of the St. Lucie Unit No. 2 Design against the NRC Standard Review Plans was conducted to document the degree of compliance and identify possible areas of contention. The Design Defense Documents also served to organize and develop in a rational manner the Final Safety Analysis Report (FSAR) for the St. Lucie 2 Plant.

In conjunction with this effort, a detailed three party (Ebasco, FPL & C.E.) integrated schedule indicating preparation and review, primary and secondary responsibilities of all sections of the FSAR was prepared with Ebasco responsible for the control and production of the document.

Also, an integrated Licensing Team Organization (Chart 18) was established so that each identified licensing task had a three party team assigned to handle all activities associated with the task in compliance with the established schedule. (Chart 19)

To insure that the licensing effort was supportive of the project objectives an overall plan was developed for this phase of the project.

As a result licensing was removed from the critical path of the project by reducing the time span of "Docketing of FSAR" to ACRS letter recommending operating license to 9 months verses 19 to 21 months pre-TMI days.

CONTROL ROOM DESIGN REVIEW

In response to an NRC requirement a Control Room Review Program organization was established. (Chart 20) The review was conducted as delineated in four phases, as follows:

Phase 1 <u>Project Planning</u>. Detailed Control Room Design Review Program Plan was prepared.

Phase 2 <u>Control Room Review</u>. This represents the period in which data collection, reduction and analysis is conducted, resulting in Human Engineering Discrepancy (HED) reports.

Phase 3 <u>Enhancement & Design Solutions</u>. Discrepancies are collated, alternate enhancements and design solutions are generated and the results are considered in trade-offs.

Phase 4 <u>Reporting</u>. Results of detailed control room design review with plans for modifications are published.

The items identified and reported on in Phase 4 that required completion prior to the issuance of the Operating License were turned over to the Startup department. Startup handled the interface with Construction and the integration into the overall Construction Schedule.

TURKEY POINT UNITS 3 & 4 - STEAM GENERATOR REPLACEMENT

While not directly related to St. Lucie, another project was done at Florida Power & Light Company utilizing similar techniques.

The steam generator replacement at Turkey Point Units 3 and 4 became necessary due to continued degredation of the tubes caused by corrosion induced stress cracking. The replacement program consisted of replacement of the tube bundles by cutting the steam generators at the channel head immediately below the tube sheet and above the tube bundle U-bends in the transition cone area. During the outage, the upper assemblies (steam domes) were refurbished by replacing the primary and secondary moisture separator packages and feedrings. The replacement outage on Unit 3 began June 24, 1981 and returned to power April 10, 1982. The Unit 4 outage began October 10, 1982, and the unit returned to service May 10, 1983.

When the problem became serious in 1976, FPL planned a phased approach to the steam generator replacement. In Phase 1 a model was built to aid in preparing a detailed scope document. Phase 2 was the awarding of the engineering contract to Bechtel Power Corporation and the establishment of an integrated project organization. Engineering was completed and with the aid of the model procurement of long lead time items was started. Phase 3 was the actual replacement of the steam generator with enginering completed and all material on site. This phased and integrated approach gave FPL the opportunity to stop the replacement of the steam generators if a repair solution became feasible without incurring a financial loss due to early engineering or procurement activities.

Upon completion of the Unit 3 replacement project a critique was conducted from which improvements were made to the Unit 4 effort. As a result, the second project was accomplished in 7 months vs. 9 months for the first. (Chart 21)

SUMMARY

The success of the St. Lucie Unit 2 project can be at least in part attributed to planning the work, accurate and timely reporting of results via valid indicators, well trained and skilled personnel and most of all teamwork.

There were many other ingredients which also contributed to the success of the St. Lucie Unit 2 project. These are summarized in Chart 22.

The ongoing critique was also a significant contributor. Utilizing task teams numerous problems were identified and solved.

While we currently have no new nuclear projects on which to apply our skills we have initiated a Corporate Quality Improvement Program which utilizes many of the ingredients that helped make the St. Lucie Project a success.

The Quality Improvement Program (QIP) for example utilizes teams for problem solving, indicators and incentives. This program is described in Charts 23, 24, 25 and 26. It is our intention to have every employee trained and involved in the QIP.

As you can see in Charts 27 and 28, many people have been trained and we are well on our way toward achieving our objective, which is for all work---"Do it right the first time."

FLORIDA POWER & LIGHT COMPANY

COMPARISON OF CONSTRUCTION START TO FUEL LOAD*

PLANT	FUEL LOAD	NUMBER OF MONTHS
McGUIRE 1	1/81	117
LASALLE 1	4/82	103
GRAND GULF 1	5/82	92
SUSQUEHANNA	8/82	100
SUMMER 1	8/82	112
SHOREHAM 1	2/83	124
SAN ONOFRE 2	2/82	96
WATERFORD 3	5/83	102
ST. LUCIE 2	3/83	71
BYRON 1	8/83	100
ENRICO FERMI 2	6/83	169
COMANCHE PEAK 1	6/83	104
CALLAWAY 1	4/84	103
MIDLAND 2	7/83	124
WATTS BAR 1	8/83	127
PALO VERDE 1	8/83	87
WASHINGTON NUCLEAR 2	9/83	133
PERRY 1	11/83	109
SEABROOK 1	9/84	99
WOLF CREEK 1	10/84	93
LIMERICK 1	10/84	173
CATAWBA 1	10/84	125
HARRIS 1	12/84	131
BRAIDWOOD 1	4/85	116
RIVER BEND 1	4/85	72
BELLEFONTE 1	5/85	128
WASHINGTON NUCLEAR 3	6/85	98
MILLSTONE 3	12/85	139
BEAVER VALLEY 2	12/85	140

CHART 1

* SOURCE NRC YELLOW BOOK – JUNE 1982

FLORIDA POWER & LIGHT COMPANY

COMPARISON OF CONSTRUCTION START TO COLD HYDRO

PLANT	MWE	NUMBER OF MONTHS
BYRON 1	1120	75
DIABLO CANYON 1	1084	84
FARLEY 2	829	82
McGUIRE 1	1180	88
NORTH ANNA 2	907	101
SALEM 2	870	125
SAN ONOFRE 2	1140	79
SEQUOYAH 1	1128	114
SEQUOYAH 2	1148	133
ST. LUCIE 2	**802**	**59**
SUMMER 1	900	79
WATTS BAR 1	1165	105
AVERAGE TIME (Months)		**95**

CHART 2

FLORIDA POWER & LIGHT COMPANY

PROGRESS VS. INDUSTRY PERFORMANCE

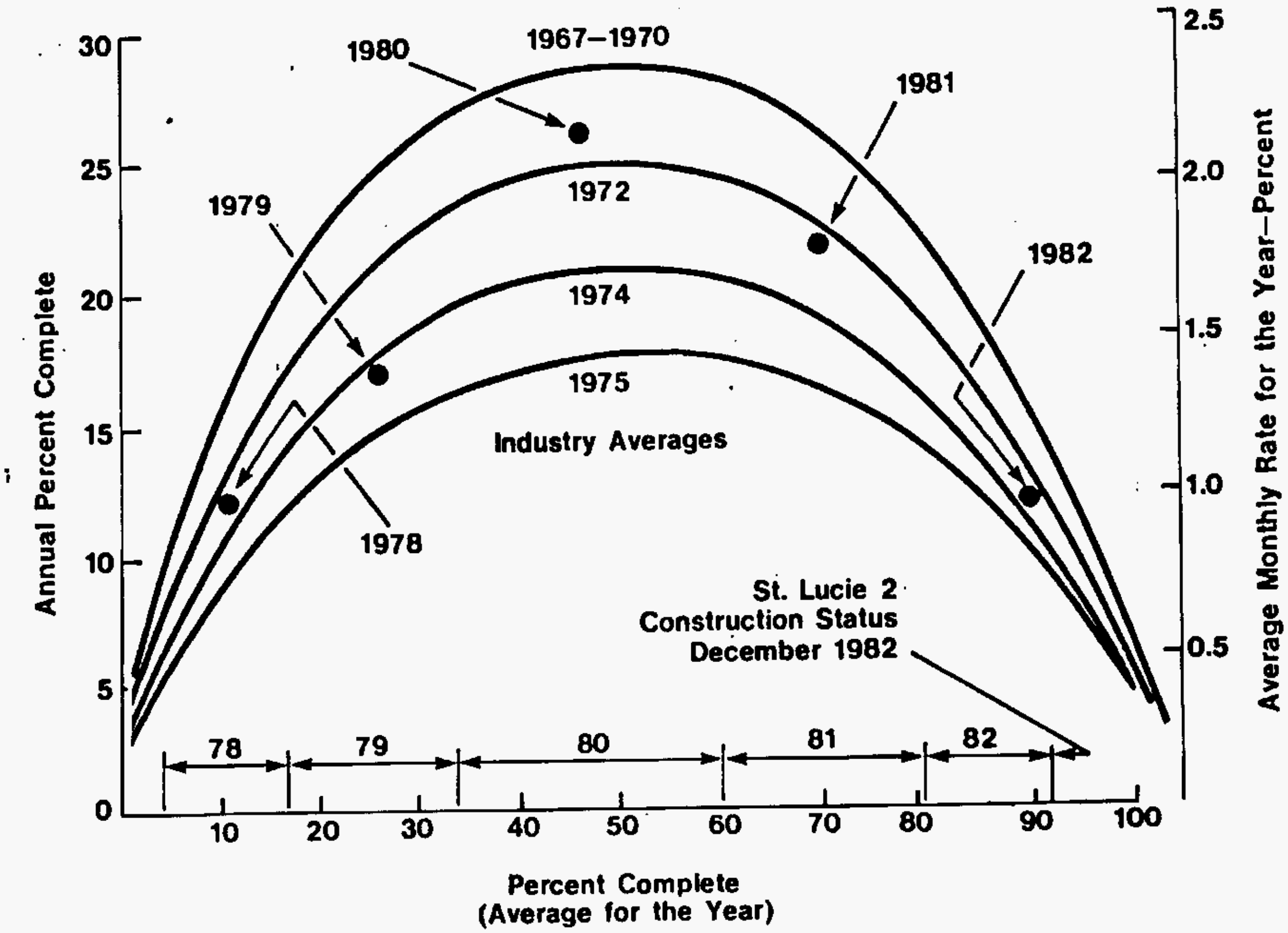

CHART 3

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FLORIDA POWER & LIGHT COMPANY

COMPLETED MILESTONE ANALYSIS

ITEM	SCHEDULED	ACTUAL
CONSTRUCTION PERMIT	JUNE, 1977	
START RCB BASEMAT CONCRETE	07/06/77	07/07/77
START INTAKE STRUCT BASEMAT CONCRETE	10/15/77	10/01/77
START T.O. PEDESTAL MAT CONCRETE	12/15/77	10/25/77
START ERECT STEEL CONTAINMENT	01/18/78	12/21/77
START RAB BASEMAT CONCRETE	02/10/78	02/10/78
COMPLETE POST WELD HEAT TREATMENT	12/10/78	01/22/79
START M.S.T. STEEL ERECTION	12/28/78	02/12/79
START RCB INT. CONCRETE	01/17/79	11/07/78
START FHB BASEMAT CONCRETE	05/05/79	06/05/79
START PREOPERATIONAL TESTING	04/20/80	03/19/80
START SETTING NSSS MAJOR EQUIPMENT	06/18/80	06/22/80
COMPLETE RCB OPER FLOOR CONCRETE	09/23/80	10/17/80
SET CONTAINMENT VESSEL DOME	09/26/80	10/04/80
COMPLETE RAB EXT. CONCRETE	12/15/80	12/18/80
COMPLETE LOOP LARGE BORE PIPING	03/14/81	02/06/81
COMPLETE REFUELING WATER STORAGE TANK	04/30/81	04/28/81
COMPLETE RCB EXTERIOR SHIELD WALL CONCRETE	09/06/81	08/11/81
INTAKE COOLING WATER INT. MTR RUN	09/25/81	09/23/81
COMPLETE OCEAN DISCHARGE PPG (KIEWIT)	12/25/81	10/14/81
TURBINE ON TURNING GEAR	12/15/81	12/16/81

CHART 4

FLORIDA POWER & LIGHT COMPANY

COMPLETED MILESTONE ANALYSIS

ITEM	SCHEDULED	ACTUAL
ECCS FLOW TEST	01/04/82	01/13/82
SECONDARY HYDRO	02/04/82	02/04/82
COLD HYDRO	03/17/82	05/19/82
HOT FUNCTIONAL	07/03/82	10/21/82
ILRT	08/11/82	11/24/82
START SAFEGUARDS TEST	09/20/82	02/23/83
COMPLETE FUEL DELIVERY	09/30/82	12/30/82
START CORE LOAD	10/28/82	04/06/83
HOT OPS II	11/30/82	05/07/83
START CRIT. & PERF. TESTS	12/21/82	06/02/83
START PWR. ESCALATION (5% PWR)	01/05/83	06/13/83
COMMERCIAL OPERATION	05/28/83	8/8/83

CHART 5

FLORIDA POWER & LIGHT COMPANY

HISTORY OF ST. LUCIE UNIT NO. 2

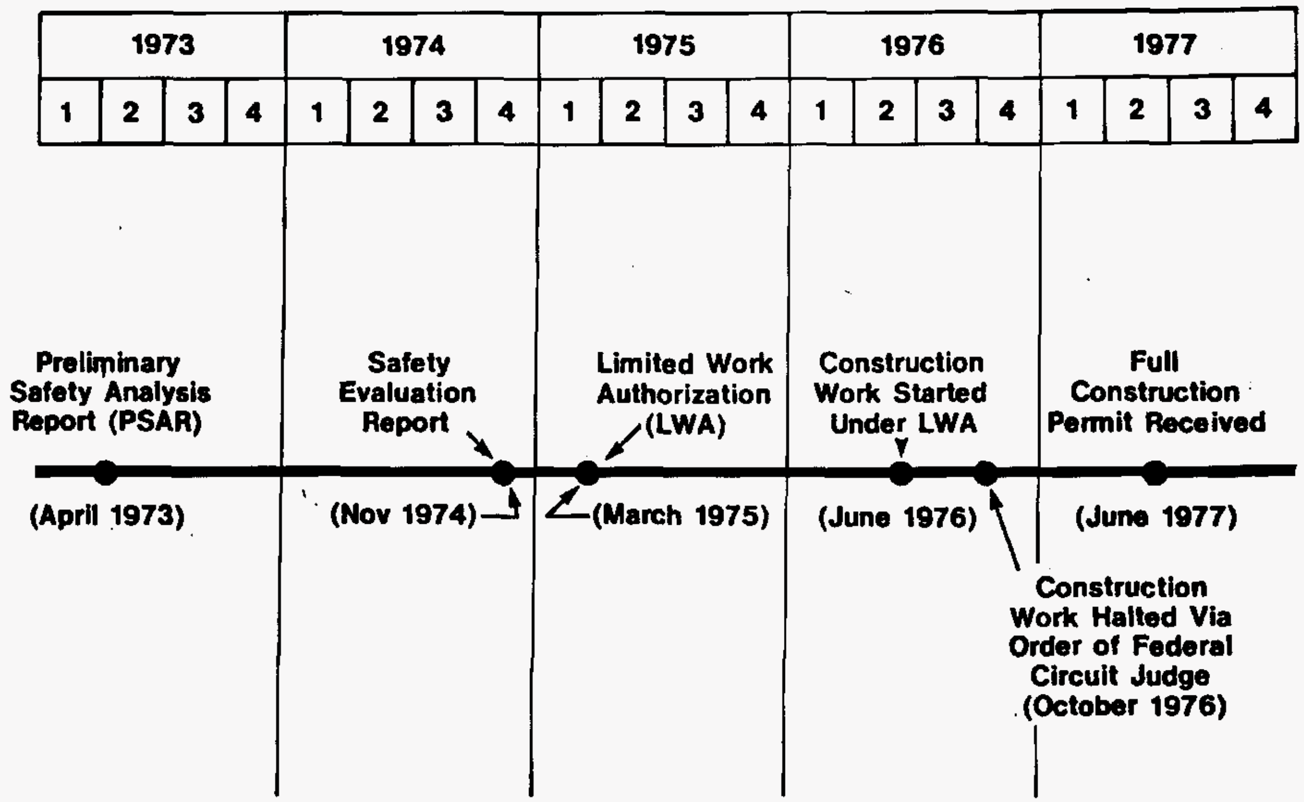

CHART 6

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FLORIDA POWER & LIGHT COMPANY
ST. LUCIE UNIT NO. 2

PROJECT ORGANIZATION CHART

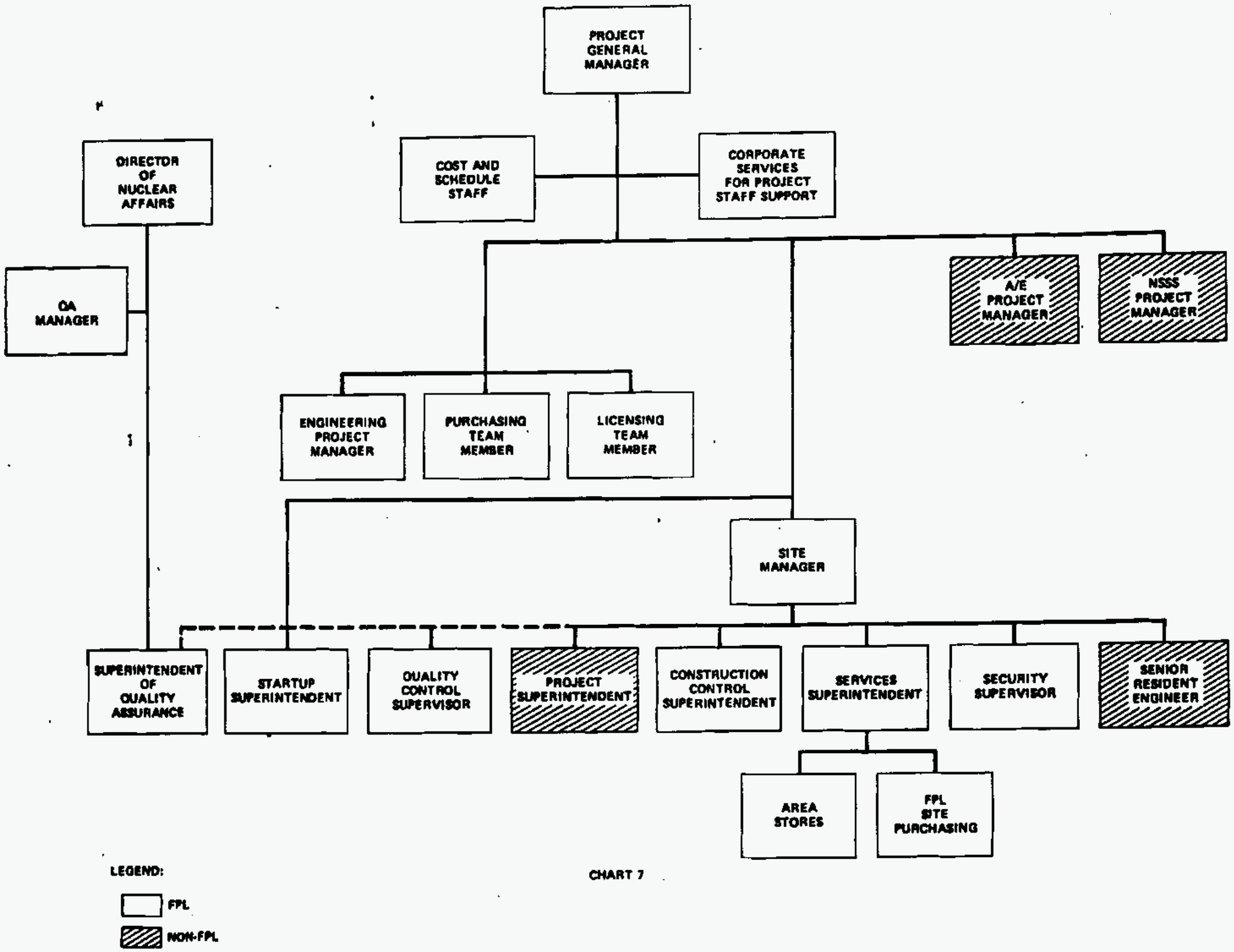

CHART 7

Docket No. 110009-EI
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FLORIDA POWER & LIGHT COMPANY

CONSTRUCTION SCHEDULING FORMAT

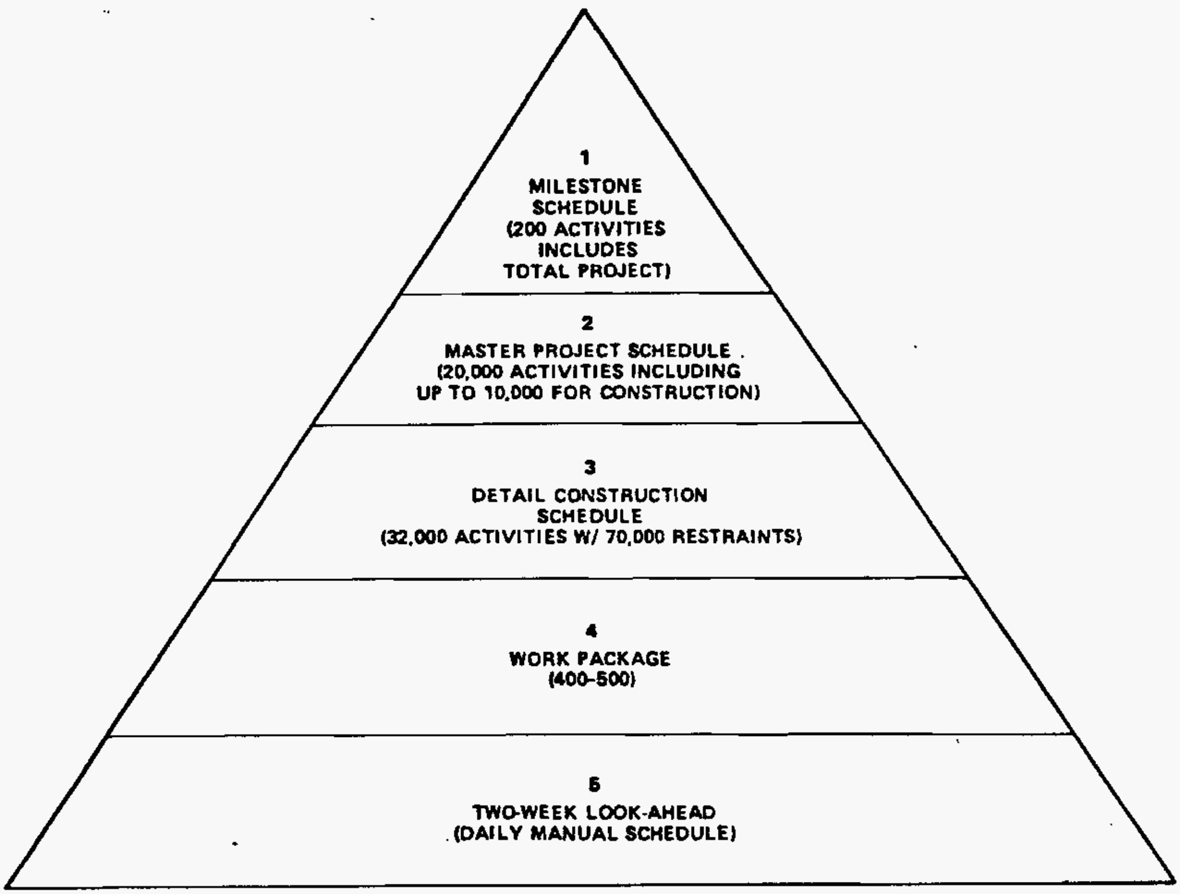
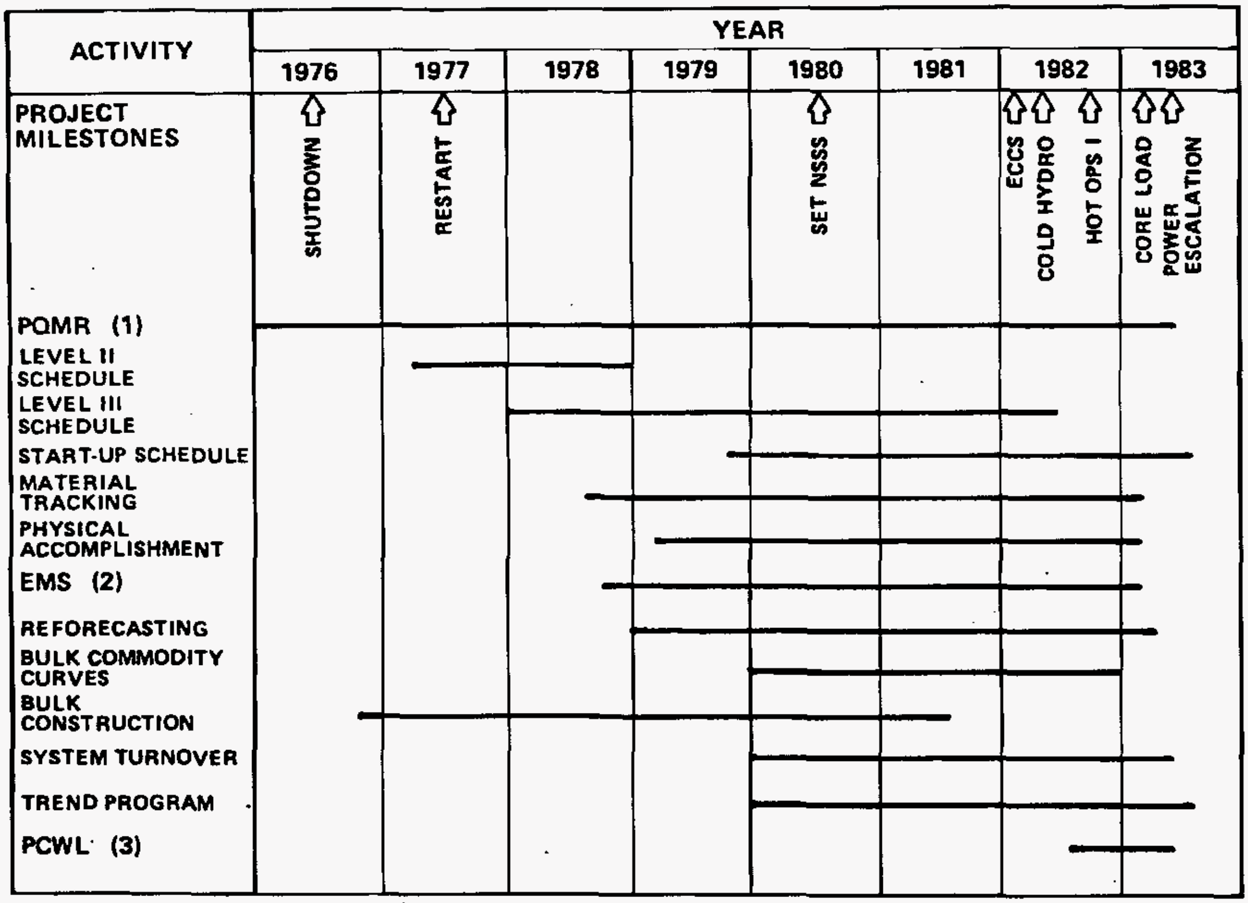


CHART 8

FLORIDA POWER & LIGHT COMPANY

IMPLEMENTATION SCHEDULE OF CONTROL TOOLS



(1) PROJECT QUANTITY AND MANHOUR REPORT
(2) ELECTRICAL MANAGEMENT SYSTEM
(3) PROJECT COMPLETION WORK LIST

CHART 9

FLORIDA POWER & LIGHT COMPANY

PROJECT PHYSICAL ACCOMPLISHMENT

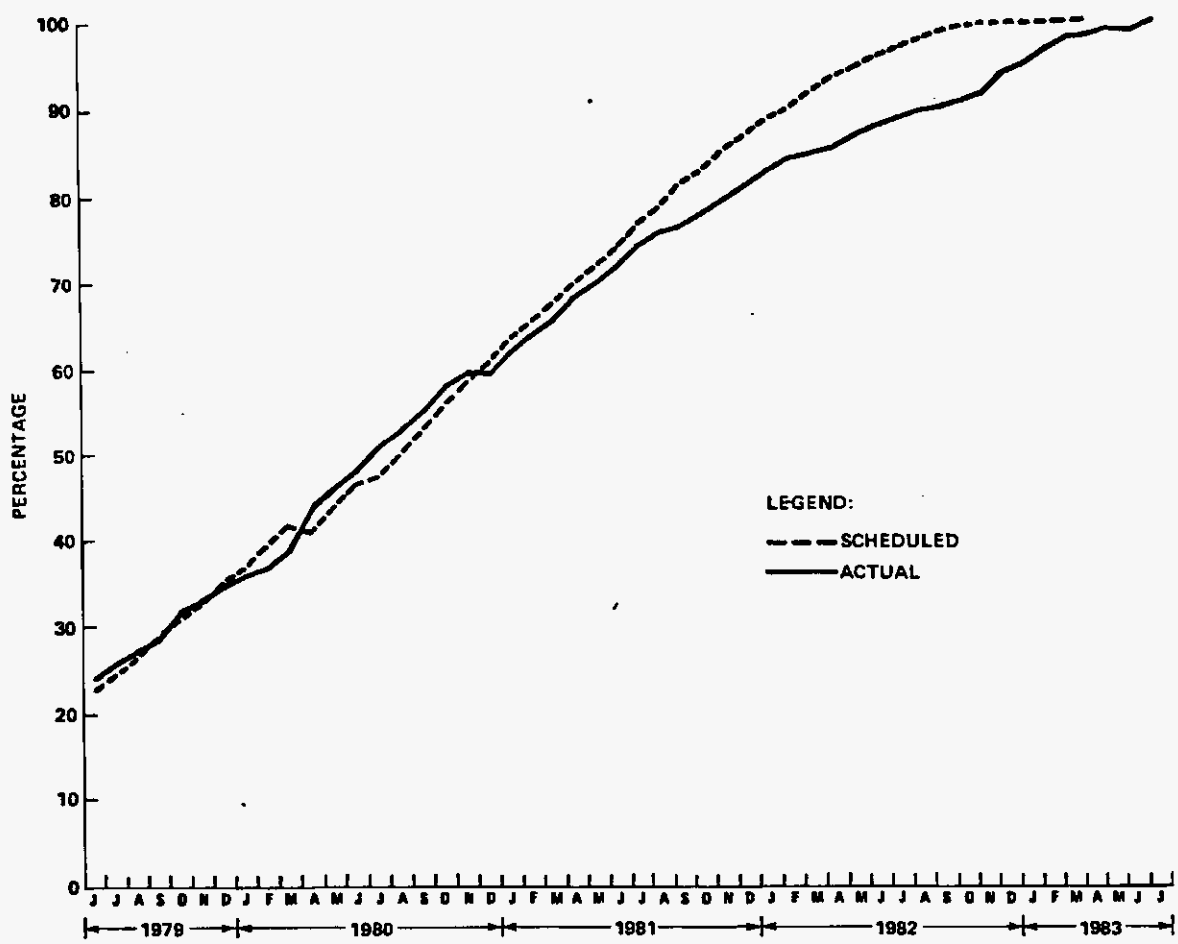


CHART 10

FLORIDA POWER & LIGHT COMPANY

SCHEDULE VARIANCE ON CRITICAL PATH

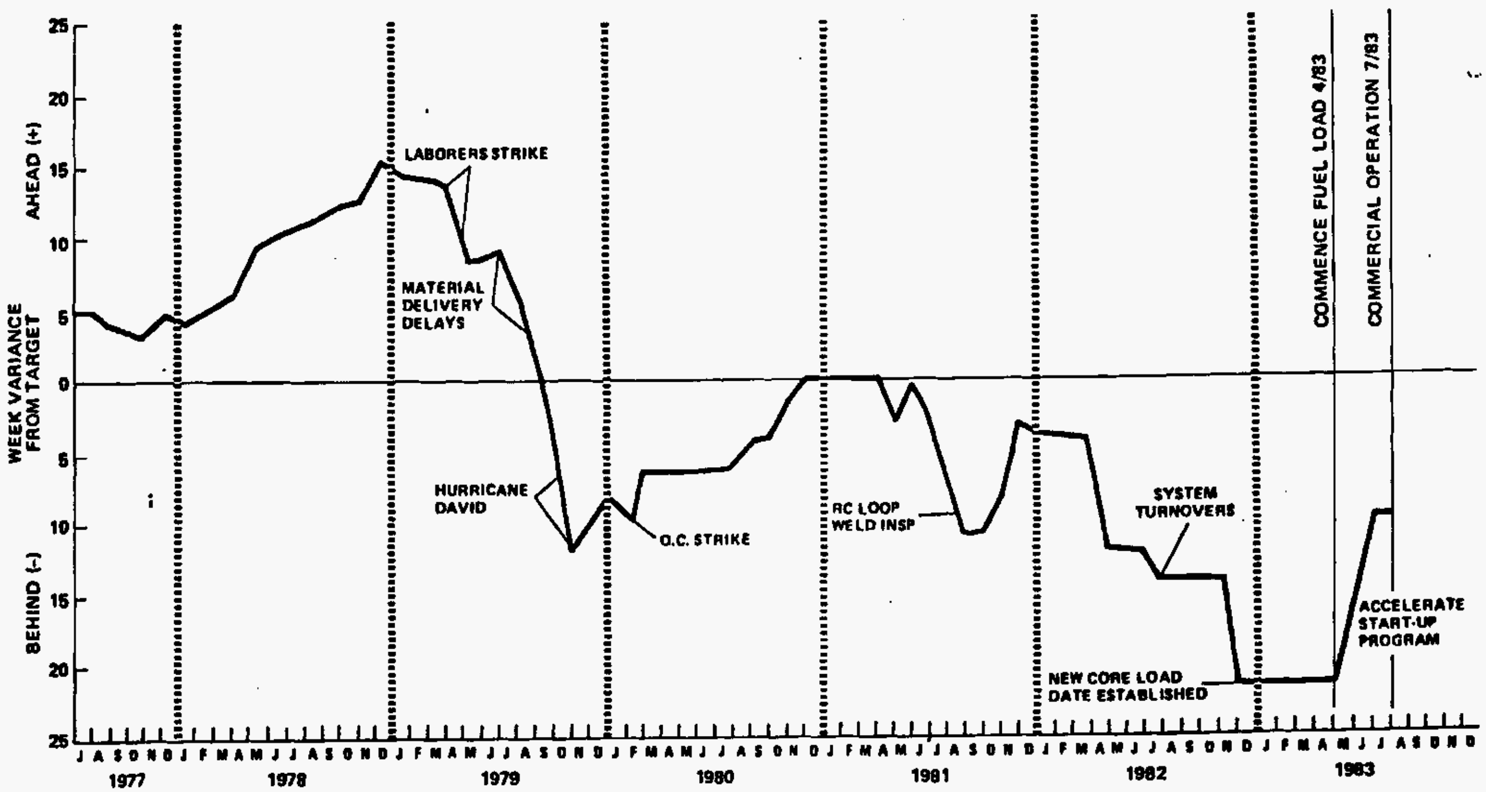


CHART 11

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FLORIDA POWER & LIGHT COMPANY

PRODUCTIVITY INDICATORS
PROJECT

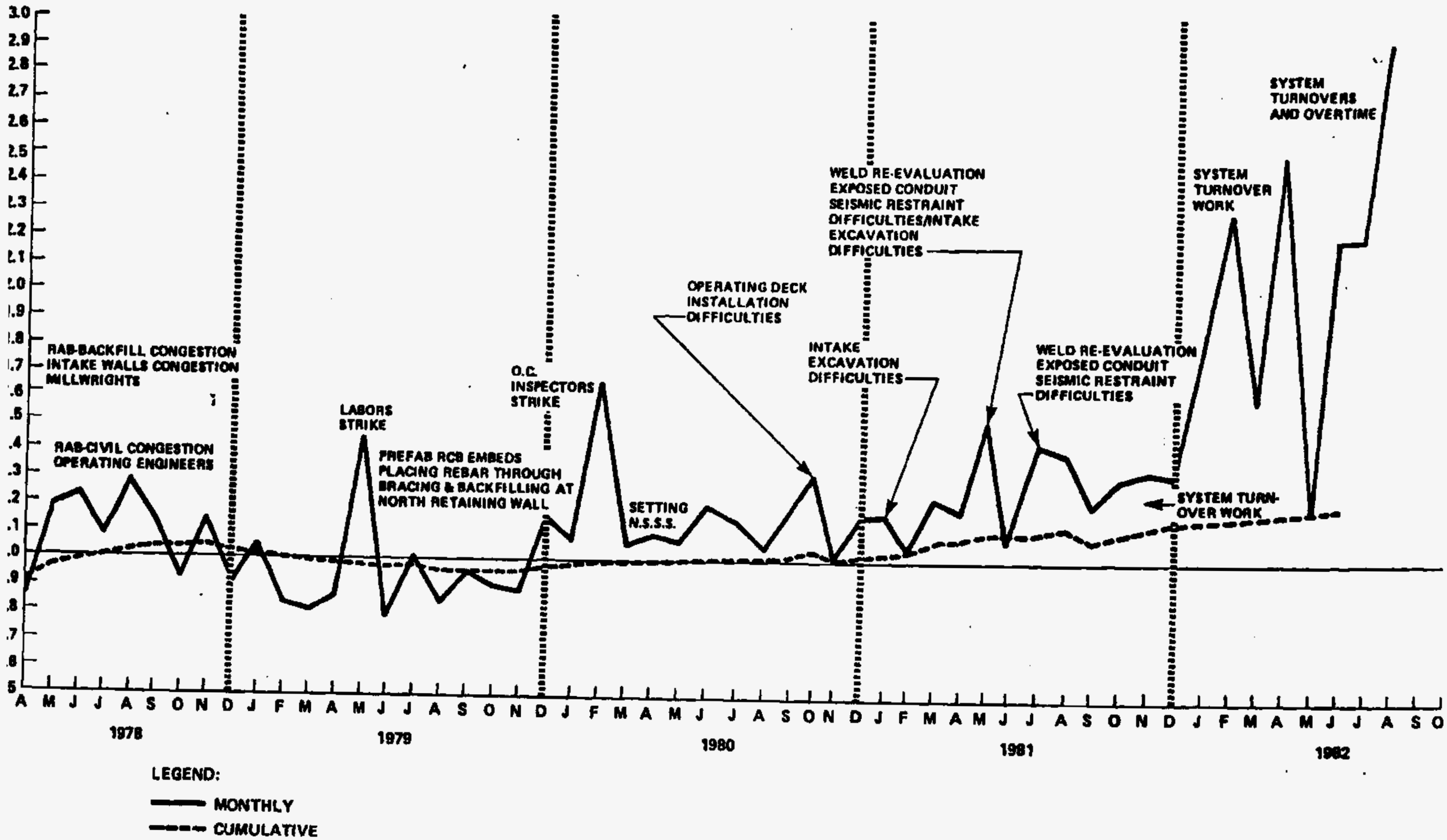

CHART 12

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FLORIDA POWER & LIGHT COMPANY

SELECTED QUANTITY STATUS
(For Core Load)

COMMODITY	FORECAST PERCENT COMPLETE BY INDUSTRY MODEL	PSL NO. 2 ACTUAL PERCENT COMPLETE AS OF 2/13/83	TOTAL PROJECT FORECASTED QUANTITIES AS OF 2/13/83	QUANTITIES TO GO AS OF 2/13/83
TERMINATIONS	89.0	96.9	112,456	1,000
CABLE	92.0	98.6	4,023,070	10,000
SMALL BORE PIPE	94.5	97.6	95,964	2,341
CABLE TRAY	100.0	100.0	40,463	0
CONDUIT	93.0	98.4	426,529	1,500
LARGE BORE PIPE	95.0	100.0	80,279	0
LARGE BORE PIPE HANGERS	—	98.6	4,404	60

CHART 13

FLORIDA POWER & LIGHT COMPANY

SITE ORGANIZATION CHART

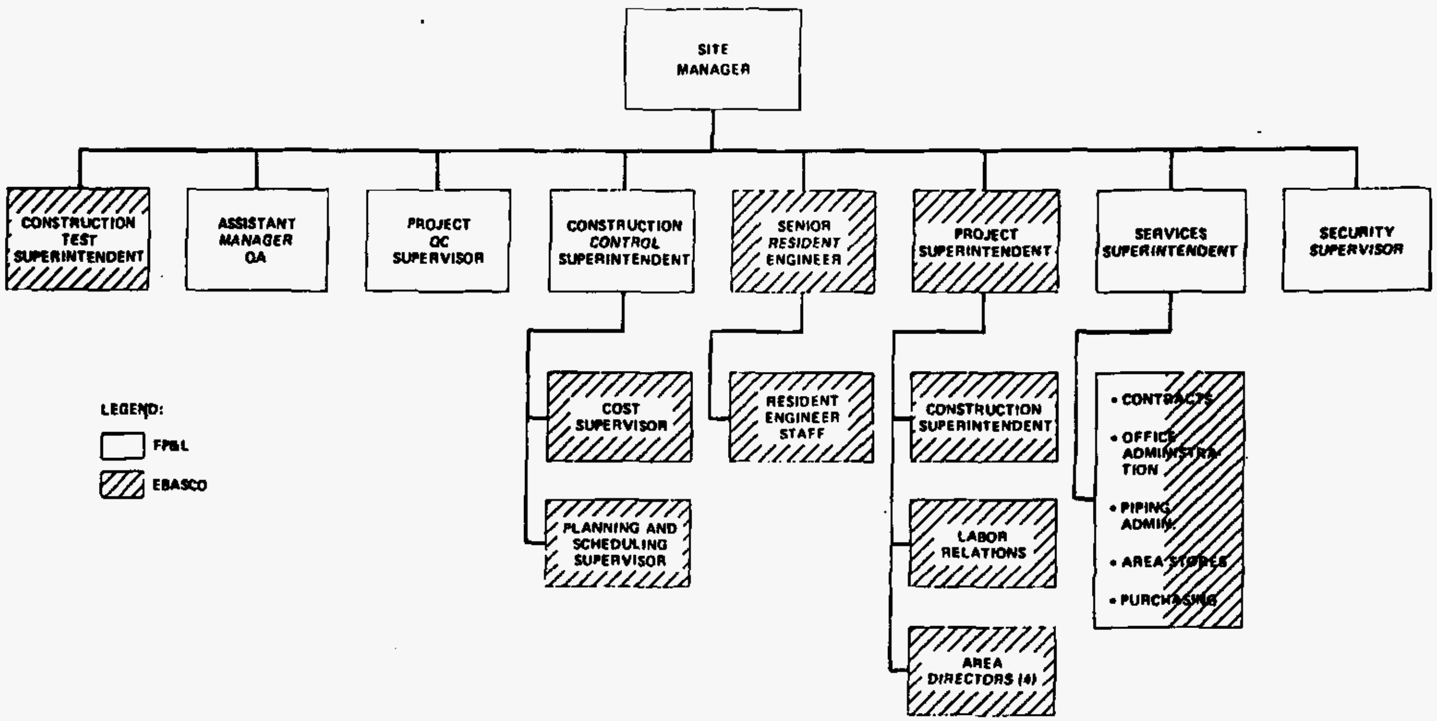

CHART 14

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FLORIDA POWER & LIGHT COMPANY

PRODUCTIVITY & QUALITY IMPROVEMENT

PAST EFFORTS

- PERIODIC WORK SAMPLING PROGRAM
  - BY CRAFT AND BY AREAS
  - EQUIPMENT (CRANES AND CHERRY PICKERS)
- OPERATIONS ANALYSIS OF AREAS SUCH AS STEEL ERECTION OF THE TURBINE GENERATOR BUILDING
- SUPERVISORS UTILIZATION STUDY
- OFFICE ENGINEERING STUDY
- CHANGE REVIEWS
- PRODUCTIVITY SEMINARS
- ASSESSMENT OF ST. LUCIE'S WORK SAMPLING RESULTS AGAINST INDUSTRY STANDARDS
- FOREMEN/CRAFTSMEN DELAY SURVEY
- QUALITY OF WORKING LIFE IMPROVEMENTS
- MATERIAL TRACKING SYSTEM
- NEWSLETTER
- UP-FRONT PLANNING IN IDENTIFYING SYSTEMS TURNOVER PROBLEMS (ASSIGNMENT OF CONSTRUCTION PERSONNEL TO SYSTEM TO PREPLAN THE WORK AND REVIEW SYSTEM PUNCH LISTS)

CHART 15

FLORIDA POWER & LIGHT COMPANY

PRODUCTIVITY & QUALITY IMPROVEMENT (CONT'D)

- PROJECT PROGRESS REVIEW REPORT
- SAFETY ACTIONS
  - MEDICAL SERVICES ENHANCED
  - SAFETY AWARDS
- SCHEDULE OR RISK ANALYSIS
- CHANGE REVIEW BOARDS
- ORGANIZATIONAL CHANGES, i.e. AREA TO CRAFT
- TOOL CONTROL PROGRAM
- MATERIALS STUDIES
- ESTABLISHMENT OF QUALITY REVIEW BOARD

CHART 15A

FLORIDA POWER & LIGHT COMPANY

MAPQ PSL 2 INDICATORS

EFFICIENCY INDICATORS

OUT/INPUT

- PRODUCTIVITY INDICATOR

UTILIZATION MEASURES

- WORK SAMPLING
- DELAY INDICATORS

EFFECTIVENESS INDICATORS

GOALS

- ABSENTEEISM
- FCR PERFORMANCE
- BUDGET PERFORMANCE
- SYSTEM TURNOVER PERFORMANCE
- TOOL COST/DIRECT LABOR
- OVERHEAD RATIO
- TOTAL CONSTRUCTION PERF. BUDGET
- LICENSE SCHEDULE
- SCHEDULE PERFORMANCE
- UNIT SCHEDULE PERFORMANCE
- PARTIAL SYSTEM TURNOVER PERFORMANCE
- FIELD STAFFING PERFORMANCE
- STORES SUPPORT
- RPA PERFORMANCE
- DCN PERFORMANCE
- OVERTIME PERCENTAGE

CHART 16

FLORIDA POWER & LIGHT COMPANY

MAPQ PSL 2 INDICATORS (CONT'D)

QUALITY

- REWORK INDICATOR
- QC HOLDS
- NCRs PERFORMANCE
- AUDIT FINDINGS

IMPACT INTERNAL

- SAFETY
- QUALITY OF WORKING LIFE
- ATTITUDE, MOTIVATION AND MORALE
- NEWSLETTERS

IMPACT EXTERNAL

- PSC, NRC, CUSTOMERS FUEL SAVINGS LOSS, AND NEWS MEDIA

CHART 16A

FLORIDA POWER & LIGHT COMPANY

NRC NUCLEAR PLANT CONSTRUCTION SCHEDULE MODEL

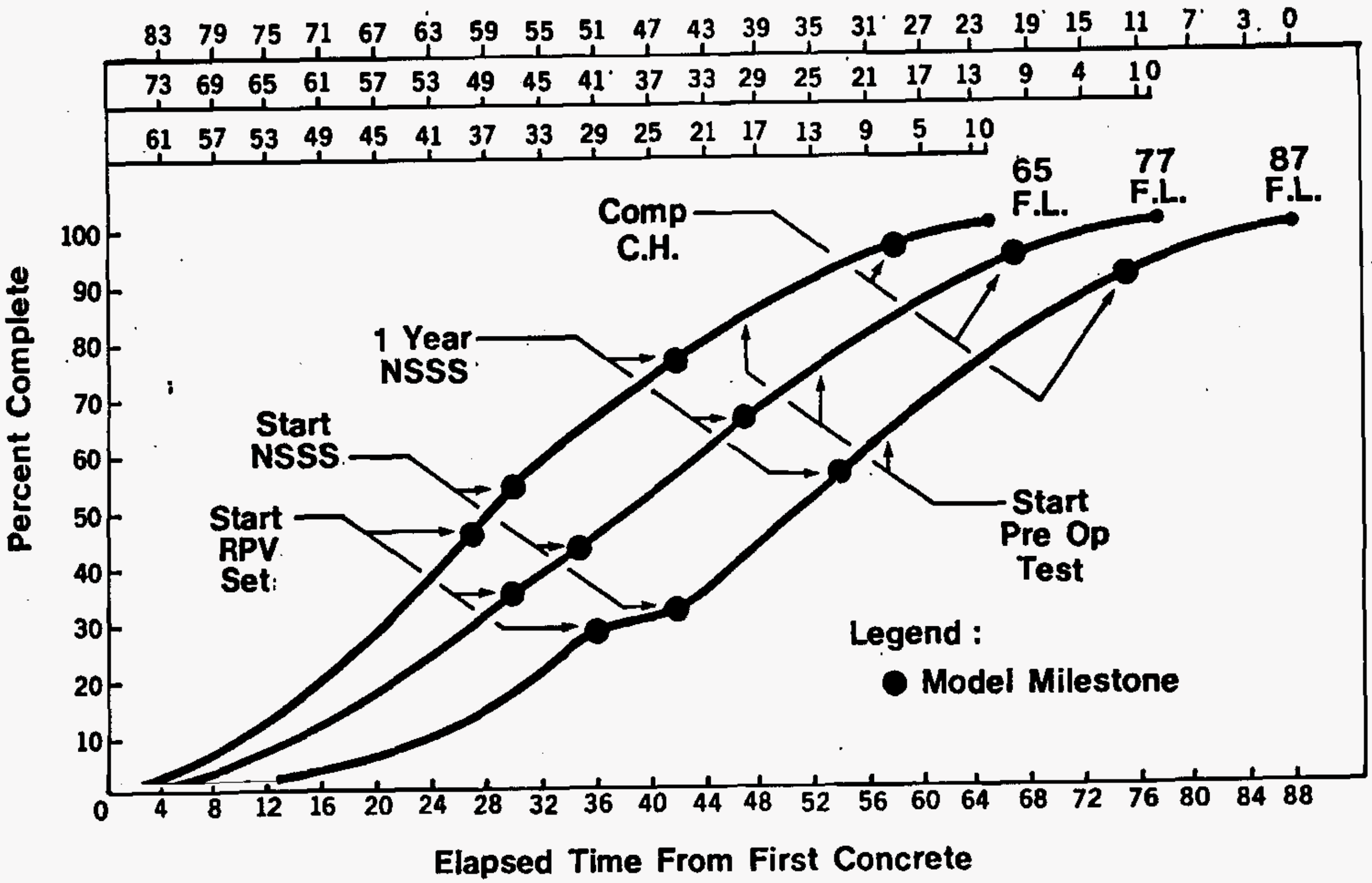

CHART 17

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FLORIDA POWER & LIGHT COMPANY

LICENSING TEAM ORGANIZATION

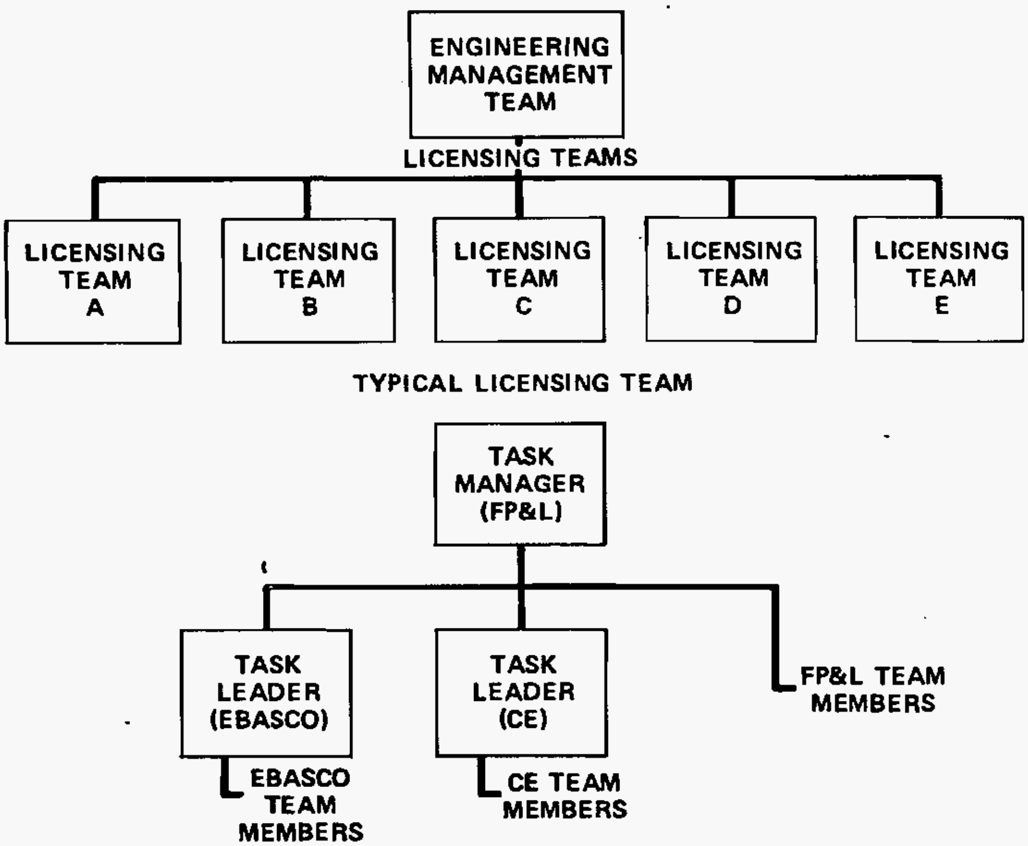


CHART 18

FLORIDA POWER & LIGHT COMPANY

LICENSING SCHEDULE FOR SUPPORT OF NOVEMBER 1982 OPERATING LICENSE (OL)

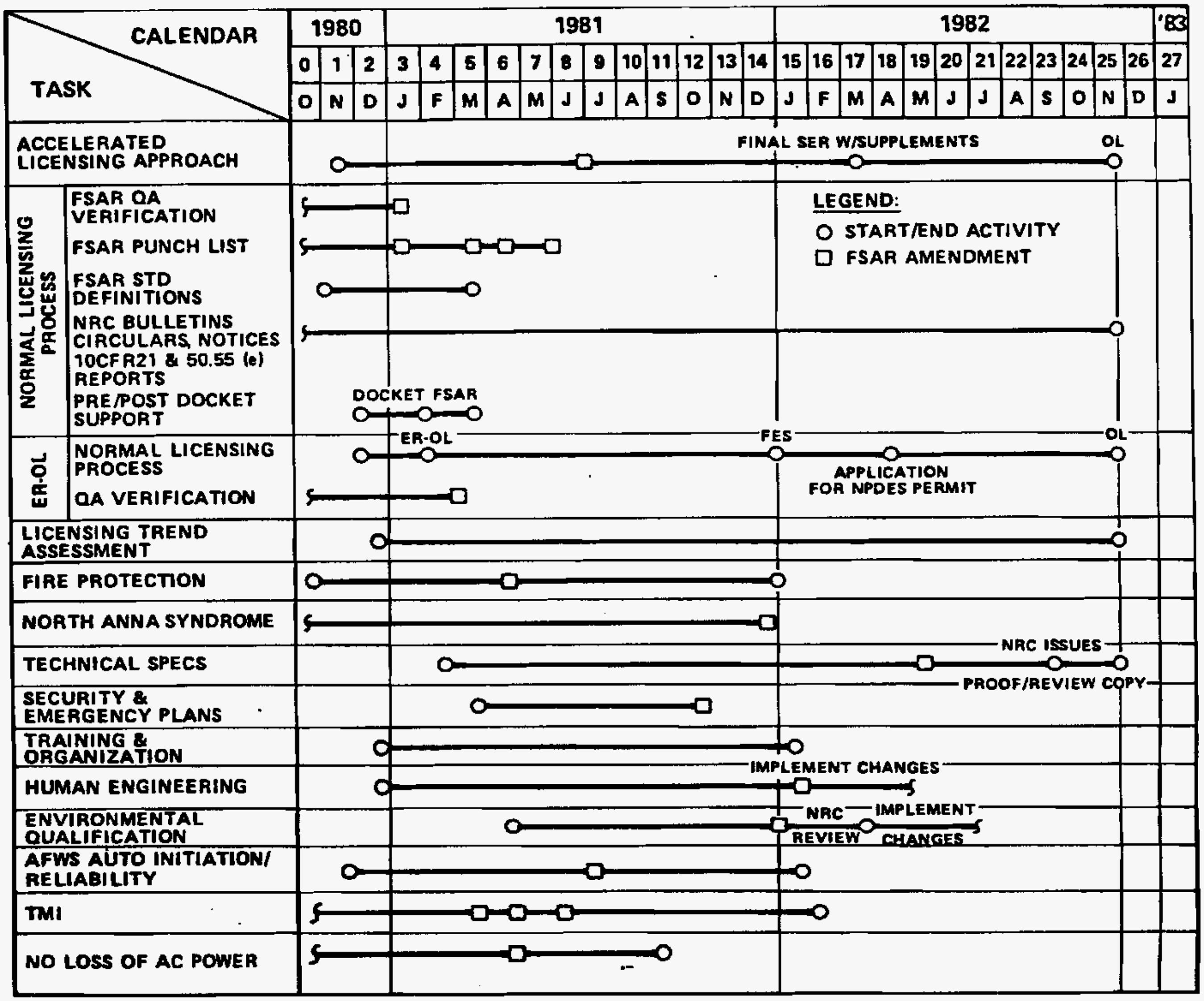


CHART 19

FLORIDA POWER & LIGHT COMPANY

DETAILED CONTROL ROOM DETAILED REVIEW PROGRAM ORGANIZATION

HUMAN ENGINEERING PROGRAM MANAGER

HUMAN FACTORS TASK TEAM COORDINATOR

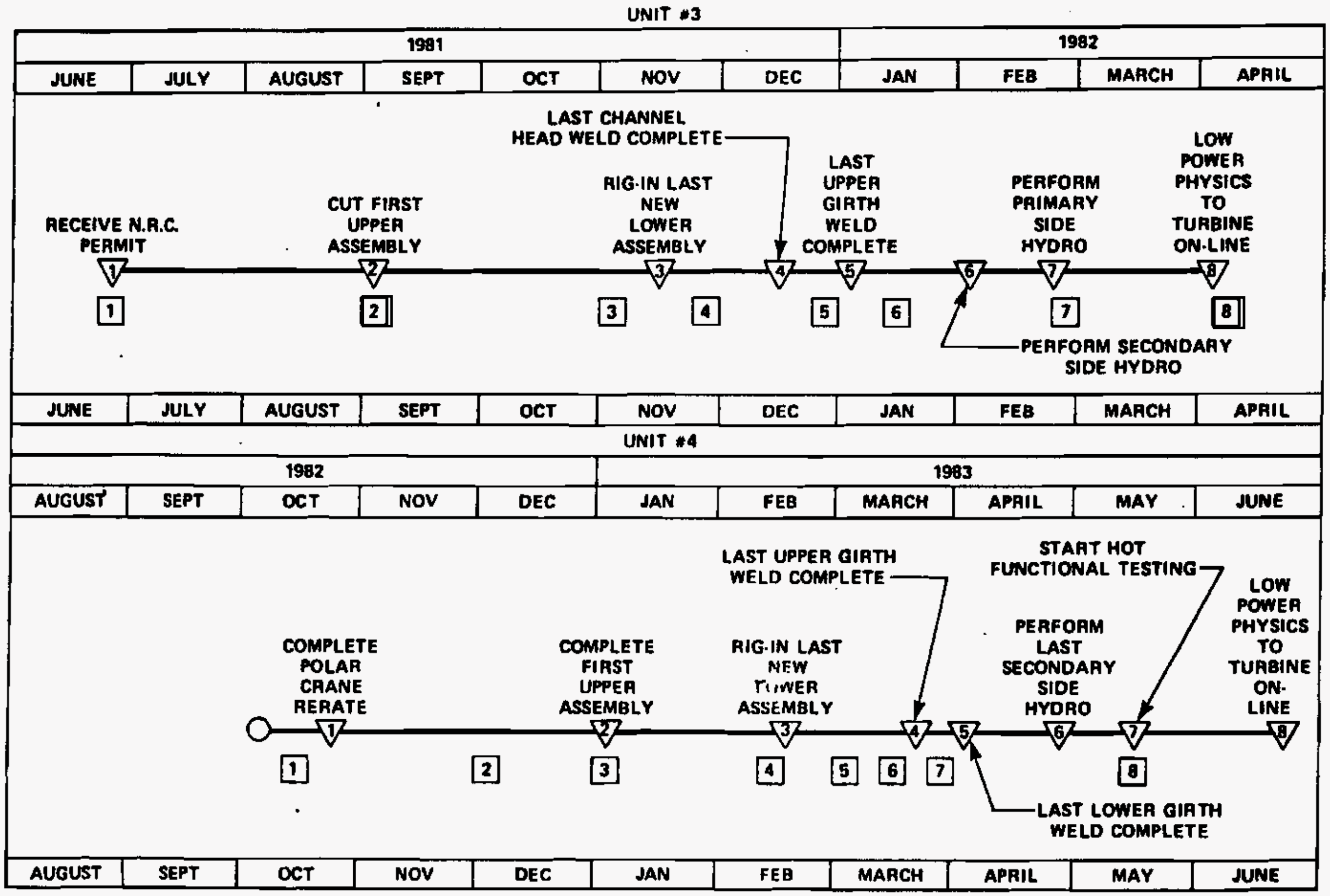
ST. LUCIE UNIT 2
HUMAN ENGINEERING
DISCREPANCY REVIEW TEAM

1. CHAIRMAN
2. HUMAN FACTORS CONSULTANT REVIEW TEAM SITE MANAGER
3. REACTOR OPERATOR
4. INSTRUMENTATION & CONTROL ENGINEER
5. HUMAN FACTORS ENGINEERING IMPLEMENTATION COORDINATOR
6. STAFF ENGINEERING (AS REQUIRED)
7. EBASCO (AS REQUIRED)

CHART 20

FLORIDA POWER & LIGHT COMPANY

TURKEY POINT UNITS #3 AND# 4
STEAM GENERATOR REPLACEMENT PROJECTS



LEGEND:

▽ = TARGET

□ = ACTUAL

CHART 21

FLORIDA POWER & LIGHT COMPANY

INGREDIENTS FOR A SUCCESSFUL PROJECT

- MANAGEMENT COMMITMENT
- FINANCIAL RESOURCES
- REALISTIC & FIRM SCHEDULE
- CLEAR DECISION MAKING AUTHORITY
- FLEXIBLE PROJECT CONTROL TOOLS
- TEAMWORK – INDIVIDUAL COMMITMENT
- ENGINEERING AHEAD OF CONSTRUCTION
- EARLY STARTUP INVOLVEMENT
- ORGANIZATIONAL FLEXIBILITY
- ONGOING CRITIQUE OF THE PROJECT
- BETHESDA OFFICE FOR LICENSING
- OWNER TAKES THE PROJECT LEAD

CHART 22

FLORIDA POWER & LIGHT COMPANY

CORPORATE OBJECTIVE FOR QUALITY

"TO INVOLVE EMPLOYEES IN EACH FUNCTIONAL AREA IN THE IMPLEMENTATION OF THE QUALITY IMPROVEMENT PROGRAM."

CHART 23

FLORIDA POWER & LIGHT COMPANY

FPL PROGRAM
QUALITY POLICY

"IT IS THE POLICY OF THE FLORIDA POWER & LIGHT COMPANY TO PURSUE AND DESERVE A REPUTATION FOR QUALITY LEADERSHIP FOR ALL OF ITS SERVICES AND PRODUCTS OFFERED; BY PROVIDING THEM IN A RELIABLE, TIMELY, EFFICIENT, AND ECONOMIC MANNER THAT WILL MERIT CUSTOMER SATISFACTION."

CHART 24

FLORIDA POWER & LIGHT COMPANY

QUALITY IMPROVEMENT TEAM ORGANIZATION

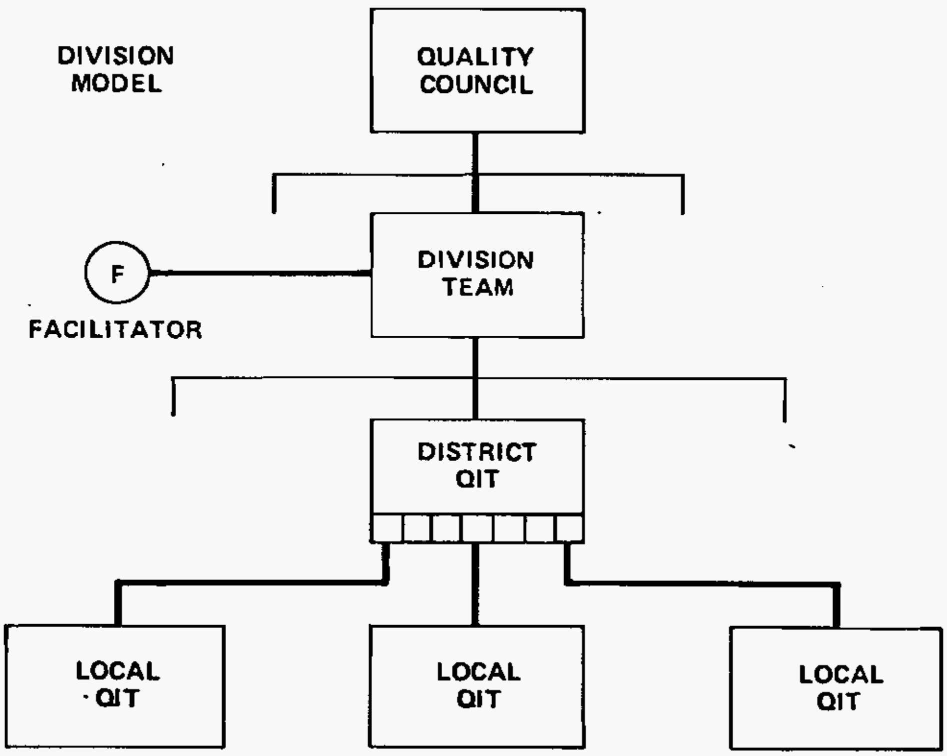


CHART 25

FLORIDA POWER & LIGHT COMPANY

QUALITY IMPROVEMENT PROGRAM IMPLEMENTATION STEPS

1. MANAGEMENT COMMITMENT
2. QUALITY IMPROVEMENT TEAM
3. MANAGEMENT ORIENTATION AND TRAINING
4. ECONOMIC ANALYSIS
5. ROOT CAUSE IDENTIFICATION
6. CORRECTIVE ACTION
7. AWARENESS
8. RECOGNITION

CHART 26

FLORIDA POWER & LIGHT COMPANY

QIP PROGRAM ASSESSMENT
(As of May 25, 1983)

PROGRAM STATUS:

• NUMBER OF – TEAM LEADERS TRAINED	290
– FACILITATORS TRAINED	43
– MANAGERS TRAINED	107
• NUMBER OF TEAMS	192
• NUMBER OF SOLUTIONS IMPLEMENTED	45
• NUMBER OF SOLUTIONS PRIORITIZED	133
• AVERAGE SAVINGS/AVOIDANCE PER SOLUTION	$232,000*

*ONLY INCLUDES LOCAL SAVINGS AND DOES NOT CREDIT ANY SYSTEM APPLICATIONS.

CHART 27

FLORIDA POWER & LIGHT COMPANY

QIP PROGRAM ASSESSMENT
(As of May 25, 1983)

COST BENEFIT OF QIP:

ANNUAL COST OF PROGRAM $1.4M

INCLUDES:	QUALITY ASSURANCE	$427K
	INFORMATION CENTRAL ..	$ 50K
	FACILITATORS	$490K
	RECOGNITION	$263K
	AWARENESS	$ 64K
	TRAINING	$107K

ANNUAL SAVINGS BASED ON
CURRENT AVERAGE .... $57 MILLION

CHART 28

WBD-3

ACHIEVING PROJECT GOALS IN CONTRASTING ENVIRONMENTS: THE VALUE OF A STRONG MANAGEMENT PHILOSOPHY

George B. Bradshaw
and
William B. Derrickson
New Hampshire Yankee Division
Public Service Company of New Hampshire

INTRODUCTION

This paper focuses on management principles that have been used successfully on two major nuclear construction projects to reach defined goals. On both projects the Project Manager (PM) directed efforts to develop a firm schedule, advertised his intentions that it would be achieved, and overcame numerous obstacles to project completion. He prevailed utilizing the principles described herein. These principles are generally applicable to any undertaking - especially large complex projects.

In addition to the difficulties of managing a large project, the Project Manager must be cognizant that every action will be reviewed when complete by prudency experts. He must take into account the perspectives of all stake holders - end users, sponsors, employees, regulators, environmentalists, public advocacy groups, intervenors, and all other parties interested in the project. To accomplish this, the PM needs practical advice, and must resist the tendency to become enamored with the next best computer system or management philosophy. He must remember the most important asset - the people doing the work.

This paper provides some useful approaches for managers, faced with these challenges and associated decisions and choices, required to carry out their task of managing a large project.

THE PROJECTS

The philosophies discussed in this paper were successfully applied to the St. Lucie Unit 2 and the Seabrook Unit 1 projects (Chart 1). Many articles (Ref. 1-4) and papers (Ref. 5, 6) have been written on the accomplishments of the St. Lucie team. They produced the only nuclear project completed on schedule in the United States at the time; a period of record inflation, record interest rates and record proliferation of U. S. Nuclear Regulatory Commission (NRC) regulations. The construction duration was 35% less than comparable projects and cost was \$1775/kw compared to a contemporary industry average near \$3000/kw. Although St. Lucie Unit 2 was a second unit, its construction began after Unit 1 went into operation with a new utility management team and many new requirements. Unit 2 did, however, utilize innovative construction practices developed by Ebasco and their contractors.

Construction of the Seabrook project was halted in April, 1984, following near bankruptcy of the lead owner, Public Service of New Hampshire. The project was restarted in June, 1984, under the management of Senior Vice President, William B. Derrickson, who was charged with taking the unit to completion after it was about 75% complete. The construction of Unit 1 was completed on schedule in July, 1986, at a savings of \$60 million below the \$830 million completion costs estimated prior to restart of construction. A license to permit fuel loading was issued by the NRC in October, 1986. Currently, the project is awaiting receipt of a low-power license, which has been delayed due to lack of participation in emergency planning by the Commonwealth of Massachusetts, and due to heavy attacks on the NRC against alternative licensing approaches.

INGREDIENTS FOR SUCCESS (IFS)

Upon completion of the St. Lucie 2 project, the NRC asked Florida Power & Light (FPL) to prepare a document analyzing the construction success. This effort lead to development of a list, by the project team, of what they thought were the ingredients which made the project a success (Chart 2). This list formed the basis for a "blue booklet" published in response to the NRC and has been used in numerous presentations given over the past five years by the authors and in an earlier Project Management Institute paper (Ref. 5). The list has also been cited by the Electric Power Research Institute (EPRI) in its study of nuclear plant lead times (Ref. 7). Similar conclusions regarding key project success factors have also been reached by Cleland (Ref. 8).

In Chart 2 the success ingredients are correlated with the six PMI body of knowledge areas. It is interesting to note those skill areas most frequently related to a success factor.

Although the combination of all twelve Ingredients for Success were critical on St. Lucie, some were of greater significance on Seabrook due to the need to adjust to a new

Project Description

	ST. LUCIE	SEABROOK
Location	Hutchinson Island, FL	Seabrook, NH
Owner	Florida Power & Light	12 New England Joint Owners*
Nuclear Steam Supply	Pressurized Water Reactor	Pressurized Water Reactor
Net Electric Output	802 MWe	1150 MWe
NSS Supplier	Combustion Engineering	Westinghouse
Architect Engineer	Ebasco Services	United Engineers & Constructors
Construction Permit	May, 1977	July, 1976
Fuel Load	April, 1983	October, 1986
Commerical Operation	August, 1983	----------
Cost to Complete	$1.45 Billion	$4.8 Billion +
Craft Manhours to Construct	16 Million Manhours	35 Million Manhours

* New Hampshire Yankee is the Management Company formed by the original sixteen Joint Owners.

Chart 1

Ingredients For A Successful Project

IFS		Time	Scope	Human Resources	Communications	Cost	Quality
1	Management Commitment	X	X	X	X	X	X
2	Financial Resources	X	X			X	
3	Realistic & Firm Schedule	X	X				X
4	Clear Decision Making Authority			X	X		X
5	Flexible Project Control Tools	X	X		X	X	
6	Teamwork – Individual Commitment			X	X		
7	Engineering Ahead of Construction	X					X
8	Early Startup Involvement	X			X		X
9	Organizational Flexibility			X	X		X
10	Ongoing Critique of the Project				X		X
11	Bethesda Office for Licensing	X	X		X		
12	Owner Takes the Project Lead	X	X	X	X	X	X

Chart 2

management philosophy. The following sections describe how each of the IFS factors affected the projects.

IFS-1 - MANAGEMENT COMMITMENT

In order for the PM to be successful he needs an unwavering corporate commitment. FPL made a decision to utilize a strong matrix PM organization on St. Lucie and stuck with it. When the project was delayed due to intervenor action in the ground breaking stage, management made the decision to continue engineering and material procurement in spite of the risk of long-term delays. Similar commitment was shown by continuing full funding on St. Lucie in 1978 during hard financial times.

The managing owners of Seabrook showed a strong commitment by going outside the project to recruit a new PM with a proven record of completing projects on schedule and under budget. Although financial backing was often limited, owners gave the PM a free hand to implement his management agenda (Chart 3). The owners also showed strong commitment in efforts to obtain an operating license through major financial support of emergency planning, media campaigns (directed to neutralizing adverse public opinion often inflamed by the politicians), and endless meetings with the regulators.

Without strong owner and corporate commitment, the PM cannot carry out his plan and philosophies.

IFS-2 - FINANCIAL RESOURCES

This was as critical on St. Lucie as Seabrook due to the turmoil in the utility industry at the time (excessive inflation, high escalation of materials and labor, and prolification of NRC requirements following the TMI accident (Chart 4)). It is listed as an important criteria since without the financial reserves to weather the many obstacles, the schedule could not be maintained while still producing a technically sound and licensable project. Adequate financial resources continues to be a major concern for Seabrook because of delays in receiving an operating license. The plant was ready in July, 1986, and remains ready to operate pending completion of the licensing process. Unfortunately, a significant accumulation of overhead and interest costs (approximately $50 million per month - $70,000 per hour) will be borne by the owners and rate-payers as a result of this extended regulatory process.

IFS-3 - REALISTIC AND FIRM SCHEDULE

This was one of the most critical success criteria for both St. Lucie and Seabrook. In the case of St. Lucie, a 65 month construction schedule was established in 1977 (two months before receiving a construction permit). Every team member commicted to this schedule and FPL did not abandon it. Variances were tracked and schedule work arounds developed in order to preserve the detailed planning base (Ref. 5). The Commercial Operation date was within ten weeks of the original schedule, a variance of less than two weeks/year. This was accomplished in spite of major unanticipated impacts by using a multitude of planning techniques, Review Boards, innovative construction methods and extensive material expediting efforts.

The first action of the new PM on Seabrook in March, 1984, was to recruit a strong Construction Director and Project Controls Manager. Their first priority was to develop single integrated schedule, based on system turnover milestones, and incorporating input from all levels of supervision. The major milestones and actual completion dates are shown on Chart 5.

The scheduling effort on Seabrook was accomplished through numerous scheduling workshops; an approach which also led to schedule ownership by supervision and subsequent accountability. Progress was monitored and objectives set at daily meetings of the Project Completion System (PCS) team, during which the PCS coordinator reviewed the status of all open items on every critical system. This forum, often of 30 team members, was a significant emotional event for those who didn't take the schedule and turnover dates seriously. Upper management reviewed the schedule during weekly staff meetings.

A realistic and firm schedule is also the best tool available to led the project through transition phases, such as from bulk construction (often with incentives to meet commodity installation rates) to startup and turnover of systems. The schedule is also a good tool for identifying needed organizational changes or to find "the right person for the job" when it is determined that performance of current supervision is lacking.

To emphasize schedule importance, a special study on Seabrook determined that 87% of the costs were time related (Chart 6). Currently, virtually 100% of the costs are time related since construction is complete.

IFS-4 - CLEAR DECISION MAKING AUTHORITY

From the project onset, individual accountabilities and lines of authority were clearly defined with strong central leadership from the PM. In the case of St. Lucie, three cost centers were established under the direction of the PM: the FPL (owner) group under the Assistant Project General Manager; the site under the direction of the FPL Site Manager; and Ebasco (Architect/Engineer) New York office under the direction of the Ebasco Project Manager. An integrated site organization, of utility and contractor personnel, was established with a further breakdown by four major construction areas (reactor containment, reactor auxiliary, turbine generator and outlying facilities). The owner established its own QA program with contractors working

Seabrook Station Unit 1 & Common

What We Said We Would Do

- ☑ Integrated Organization
- ☑ Direct Employment
- ☑ Fixed Cost Building Completion
- ☑ Nuclear Stabilization Agreement
- ☑ Project Office Bethesda
- ☑ Allegation Resolution Program
- ☑ Independent Review Team
- ☑ Other Management Actions

Chart 3

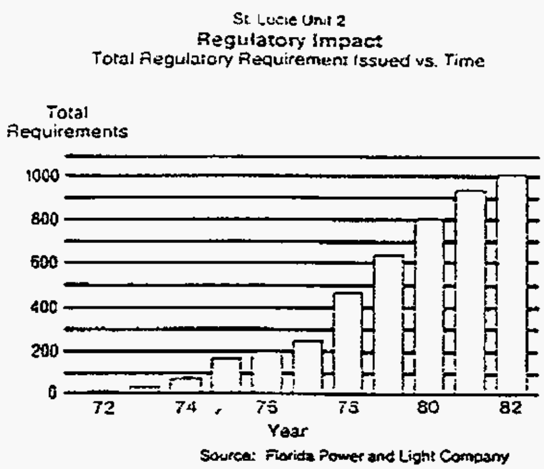


Chart 4

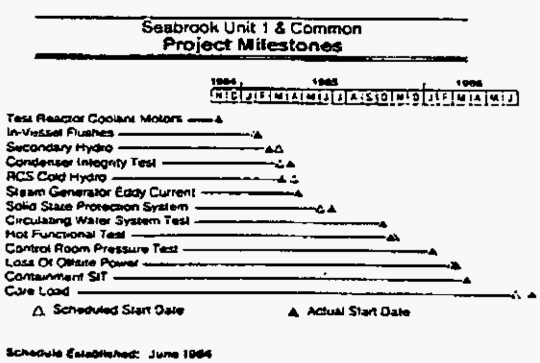


Chart 5

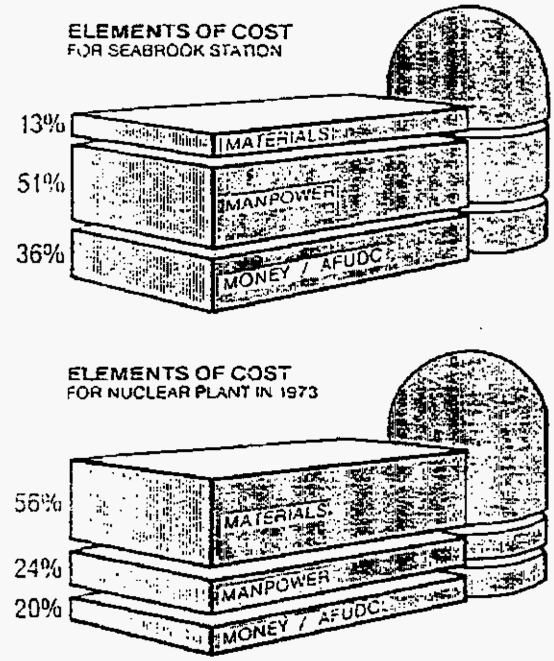


Chart 6

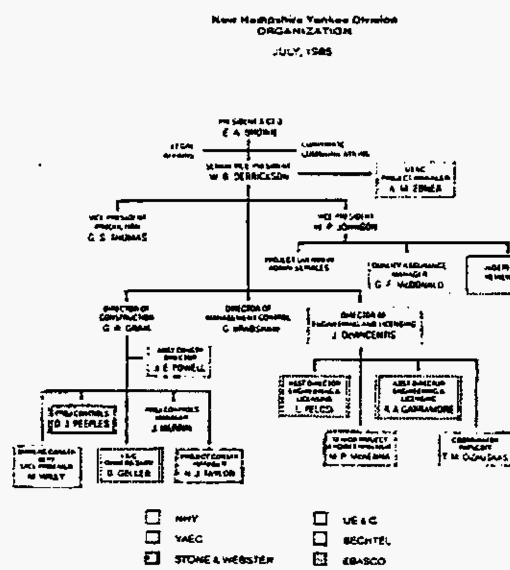


Chart 7

under FPL site construction procedures. FPL controlled all QC functions, including certifying inspectors and organizing them to maximize support to construction forces, and to minimize waiting time.

The Seabrook project was organized during 1984 in a structure similar to that used on St. Lucie (Chart 7). There was a heavy emphasis placed on selecting the best supervision for the job (regardless of company affiliation) and streamlining management by consolidating contractors. This insured optimum communications and enhanced the PM's ability to tie commitments directly to one manager. This consolidation led to timely and accurate reporting and minimal interference (confusion caused by too many layers of communication). The PM reinforced individual accountabilities during weekly staff meetings and through Independent Review Team reports.

Use of an integrated organization and flexible contractual agreements helped both projects make the needed changes when required. Knowing who's in charge removes the "fuzz factor", ensures decisions by those with a stake in it, and reduces outside interference.

IFS-5 - FLEXIBLE PROJECT CONTROL TOOLS

The key to identifying problems early and making good decisions is having accurate, reliable, detailed information. Both projects used a variety of project control tools (Ref. 5); for example, on St. Lucie a Material Tracking System followed 80,000 items equating to 5.5 million pieces of information in order to support schedules. Due to the completion of major bulk commodities on Seabrook, it was decided to rely less on computerized CPM networks and to return to hand drawn detailed schedules by both building and system which were then used to develop comprehensive punch lists of open items. The Seabrook project was also able to make valuable use of personal computers for commodity tracking, unit rate analysis, rework, and management of indirects. Indirect manhours were broken down into some forty categories in order to micromanage allocated manpower levels. A commitment budgeting process was developed that stressed accountability for controlling cost to the lowest levels possible. As the Seabrook project approaches commercial operation, a great emphasis has been placed on implementing an Information Systems Plan that identifies critical plant operational and automated business data needs. Applications are increasingly becoming mainframe based to facilitate large data bases and meet networking requirements.

IFS-6 - TEAMWORK - INDIVIDUAL COMMITMENT

Clear roles and responsibilities, selecting the best person for the position, and streamlined management organization all led to better project team work. For St. Lucie a matrix PM organization was established with an FPL Project General Manager, who was given overall authority and responsibility. The project team was made up of members from 21 FPL departments, plus the project managers from Ebasco and Combustion Engineering. For Seabrook, a project team headed by the Senior Vice President for Nuclear was established and included the PM for United Engineers and Constructors and the Westinghouse site representative (Chart 7).

One concept for obtaining commitment, that caught on especially well, was the "mother" program. Problems that had trouble finding a home were assigned a mother (responsible individual) for taking corrective action and reporting on progress. The "mother" concept was used extensively on both projects and promoted a nurturing attitude in the team.

Another approach used on Seabrook, to promote a positive project attitude, was development of a "Make It Happen" theme. Each employee was challenged to ask, "What does it take to make it happen on schedule?". Report covers, news letters, and office posters communicated the theme.

Obviously, orchestrating and directing a large complex project involved many people both in and outside the projects. FPL held regular meetings with the Building Trades Council to improve communications, and at one point FPL's executive management involved the entire Florida Congressional delegation to support licensing of the unit. Open houses were used on both projects to permit the workers, their families and residents of the surrounding communities to tour the nuclear units while under construction. On Seabrook, teamwork was also promoted through the use of milestone celebration "critiques" involving the entire site population.

IFS-7 - ENGINEERING AHEAD OF CONSTRUCTION

This factor was more critical on St. Lucie than Seabrook due to the proliferation of changes caused by new NRC regulations. The problem was approached in two ways; by forming task teams to address specific large problems, and forming a Change Review Board to assign discretionary changes to a Backfit Program for completion after commercial operation. Some 30 different task teams were used on St. Lucie to address specific issues such as fire protection and loss of offsite power. Seabrook utilizes a Engineering Change Team to review staffing levels and all work activities on a quarterly basis in order to effect tight manpower control. Engineering issues which could impact the project schedule were addressed by the Independent Review Team, to be discussed later.

IFS-8 - EARLY STARTUP INVOLVEMENT

One of the major contributing factors in the completion of both St. Lucie 2 and Seabrook 1 on schedule was the ability to turnover components and systems to the startup and operating departments in a timely manner. The overall philosophy was to schedule for the earliest possible testing of equipment for problem identification and correction. On St. Lucie, the construction and startup schedule logic was integrated to ensure timely engineering and procurement support.

When the Seabrook project was restarted after the April, 1984 shutdown, the job priorities were shifted to support startup milestones. One of the first systems to be tested were the diesel generators, in order to both check out the equipment and evaluate the effectiveness of the organization. Seabrook continued to meet all of its scheduled system milestones and eventually converted to building turnover milestones (Chart 8) in order to demonstrate project completion and turn as much control over to Operations as possible. This early building turnover program helped establish an end-of-job mentality, improved housekeeping and instilled confidence with the owners, regulators and financial community, all of whom made frequent site visits. This approach also supported a transition to the "fixed price" building completion program instituted by the PM to firm-up completion costs (Chart 9).

IFS-9 - ORGANIZATIONAL FLEXIBILITY

The PM must have the ability to reorganize the project to respond to potential "schedule busters". On St. Lucie changes were made near the end of the project to replace the piping contractor with Bechtel supervision and to bring an Ebasco VP to the site to oversee electrical completion activities. On both projects, the transition from bulk commodities to system startup required giving greater priority to the Startup organization and creating milestone coordinator positions (mothers) to direct specific completion activities. Near the end of both projects the Project Completion System (PCS) coordinator became leader of the schedule through "war room" type daily meetings.

In the case of Seabrook, the April, 1984 shutdown of the job facilitated a major reduction in the number of contractors and labor force, and a streamlining of the management structure. During restaffing a special task group was setup to rapidly identify and attract qualified candidates for critical supervisory positions which matched in experience and philosophy.

IFS-10 - ON-GOING CRITIQUE OF THE PROJECT

Judged to be one of the most useful activities on both projects was the use of on-going task force studies. At St. Lucie, independent study teams were used to perform schedule risk analyses; conduct quality assurance program reviews; verify engineering design bases; and perform NRC type licensing reviews of selected systems to assist in completing the FSAR review on schedule. Overall ten major reviews were conducted (Ref. 5), including many directed at improving craft and supervisor productivity.

During the last three years of Seabrook, a multi-discipline Independent Review Team was utilized to perform dozens of project reviews. Some of them required special expertise of consultants, such as Duke Power and Ebasco Services. Due to the numerous complex issues encountered on the Seabrook project, the IRT could provide an assessment of risk for many problem areas at once and thus focus management's attention on the most important ones. This also removed potential bias and fear of an individual that disclosing a weakness would mean a loss of job security. The IRT review had the further benefit of supporting the decision making process and ensuring high prudency standards. The IRT concept is discussed in more detail later.

IFS-11 - BETHESDA OFFICE FOR LICENSING

This ingredient has received much attention since few other utilities undertook establishing a local Bethesda licensing office. At FPL, the PM made the decision to share an office in Bethesda, Maryland (NRC office location) with the NSSS vendor (Combustion Engineering) to facilitate the completion of the FSAR review schedule. Groups of engineers worked out of the office to resolve NRC staff reviewer questions on-the-spot, thus avoiding delays of up to 6-9 months in schedule and improving communications. In addition to the Bethesda office, an overall efficient working relation-ship was developed between the Owner and NRC at the site and in the Atlanta Region office. The NRC project manager, resident inspector, and region inspectors were all aggressive in surfacing disagreements early so they could be resolved and dispositioned without impacting the schedule.

The tradition of a Bethesda office was continued on Seabrook and has been helpful in transmitting information, coordinating hearings, responding to NRC staff issues and assisting with emergency planning reviews. Unfortunately, the current mood of the NRC is to formalize the interface with the owner. This trend may have a negative effect on the project's ability to receive a timely decision on a full-power license.

IFS-12 - OWNER TAKES THE PROJECT LEAD

This is the single most critical factor in successfully implementing the PM plan and philosophy. On St. Lucie the corporate management made an early decision to have a strong PM team and subsequently renegotiated major contracts on a cost plus fixed fee (CPFF) basis to increase owner flexibility in requesting and using engineering and construction services. This same aggressive approach was applied to the quality program, procurement activities, and startup, which was staffed mostly with utility employees. It should be noted that the commitment of the owner to take the lead on St. Lucie 2 followed two successful turn-key nuclear projects with Bechtel at Turkey Point and a cost plus construction project with Ebasco Services on St. Lucie 1. These projects developed the utility's experience base and confidence. When required, FPL hired the specific experience it lacked.

On Seabrook the project went from Construction Management with many contractors, to direct employment of crafts by UE&C, always under a cost plus fixed fee basis. The owner changed the method of supervision of craft when it was required to efficiently complete the project.

Now that we have covered the twelve major ingredients for success, let's examine some of philosophical choices for managing a large project.

THE PHILOSOPHICAL CHOICES

A project team may perhaps consist of thousands of persons whose behavior, training, and upbringing are all different. In order to reach some manner of philosophical equilibrium with the project team it is necessary for the PM to develop his project philosophy. Over the years, the following principles have consistently proven to be winners toward this goal:

- Manage by objectives - rely on schedules, milestones, tasks, quality goals, stay out of details (rely on management skills rather than content knowledge), etc.
- Create a positive "you gotta believe" atmosphere - avoid negativism in order to motivate the team (you must be confident of your ability).
- Don't let things get started that you don't want to put up with (such as finger pointers) - bad habits are hard to break.
- Keep it simple - large complex projects are completed one task at a time; don't let the size of the project cloud your thought.
- Have a sound basis for all decisions - well documented bases are essential for assuring that the job is prudently managed.
- Admit mistakes early and move forward - use mistakes as an opportunity to learn; don't affix blame or create an atmosphere of fear.
- Be honest with yourself and the team - tell it like it is; they need to hear it from you.
- Be a good listener - people need someone to listen, and often something of value may be learned.
- Be a team player and leader - a team can accomplish almost anything.
- Take the time up front to solve problems and foster a "do it right the first time" approach.
- Get help - there's nothing wrong with that and the sooner the best help is obtained, the sooner a critical problem will likely be solved.
- Independent reviews are good business (as we've discussed).
- Enjoy what you are doing - this will usually come if you are comfortable in the job and can "be yourself".
- Don't be encumbered by the past - what's done is beyond change; concentrate on the future.

"Happy families are all alike; every unhappy family is unhappy in its own way". This quote from Leo Tolstoy's sad tale of Anna Karenina has been used to describe the nuclear industry's troubles. The project manager's goal should be to develop a team that is a "happy family" - his family!

GETTING ORGANIZED

Considerable effort went into selecting the organization structure used on St. Lucie and Seabrook. The questions and criteria that have been found useful for evaluating these organizations include:

- Is it balanced - no excessive authority in any one branch? No duplication of effort.
- Does it have clear responsibilities? Do you have a job description for each position, and does it define individual accountabilities accurately.
- Does it have checks and balances? Think of the three branches of the U.S. government (without the bureaucracy); is it structured similarly?
- Does it have internal equity between comparable positions in each branch? In other words, are salaries and career paths comparable for similar responsibilities?
- Are career paths provided and are they appropriate? Can people advance through the organization?
- Does it provide latitude to management? Is the organization flexible enough to allow your managers the latitude to be creative?

The organization for New Hampshire Yankee (Chart 7) was structured with these principles in mind.

OTHER PROJECT ACTIONS AT SEABROOK

To facilitate acceptance of the new organizational approaches (and associated culture changes) at Seabrook, training programs were implemented for all of the project management team. Courses included problem solving Kepner-Tregoe), team building, public speaking, managing management time and quality improvement. These courses helped promote team building communications and development of a common management language; this was especially helpful in resolving confrontations which inevitably arose as greater emphasis was placed on meeting schedules and budgets.

The problem solving training courses were useful in re-orienting project team members from being problem identifiers to becoming problem solvers. Identifying and solving the right problem takes training and is the only way to prevent reoccurrence. Clarification of roles through removal of management layers also aids problem identification and resolution at the lowest level - always the most efficient method. The team building course helped promote better interpersonal and listening skills, which was also instrumental in problem solving.

A Quality Improvement Program was used on St. Lucie and initiated on Seabrook, to promote both team building and problem solving. There is a growing body of knowledge that can be used to develop your own project QIP Training Program. Typical program implementation steps are shown on Chart 10.

On Seabrook, the transition to the new management organization and emphasis on completing systems was facilitated by consolidating all the crafts under the supervision of one contractor, UE&C, and use of the National Stabilization Agreement, which both helped streamline supervision of the craftsmen.

PROJECT COMPLETION SYSTEM (PCS)

The PCS program was utilized extensively on both St. Lucie Unit 2 and Seabrook to instill schedule accountability during the transition from bulk construction to system completion and test. Features of the program included:

- Development of a listing of open activities by system over a two week window. Approximately 10,000 items were tracked at any one time.
- Review of daily activities during a PCS meeting held in the "War Room" with construction supervisors, lead system coordinators, expeditors and other resources, as required.
- Resolution of all outstanding issues on a daily basis. This promoted a no-nonsense, no-escape approach, reinforced by strong upper management support.
- Updating of the PCS listing on a daily basis and incorporation into the system schedule.

The PCS schedule was at the lowest level of a scheduling hierarchy that included the project summary network, construction schedule and system completion schedule.

During the completion of Seabrook, the construction supervisors were accountable for meeting both commodity installation schedules (with target rates) and PCS program schedules. The dual scheduling approach was used to overcome acute problem areas, such as pipe hanger installation and HVAC completion. Ultimately the PCS became the primary control mechanism.

Success of the PCS program was tied to the inevitability of the daily meetings (held over the last two years of the job), the visibility and commitment of top management, and to the comradery ultimately achieved. Management inaction was not tolerated!

Another situation which drove the fiscal and schedule accountability on Seabrook, was the imposition of a $4 million per week cash flow constraint for the entire project after restart in July of 1984. Major milestones were considered sacred, and in order to achieve them (with a fixed manpower level), craft productivity, rework, weekend work and overtime were all tightly controlled and reviewed on a weekly basis. Milestones were sometimes redefined in order to stress schedule performance. The use of a cost center manager (CCM) commitment budget system allowed weekly accountability of all dollars expended on the project. The CCM approach became so entrenched that it has been continued through the operating phase of Seabrook. Ultimately, the weekly cash flow went to $10 million per week during the last eight months of construction.

During the application of the scheduling systems on Seabrook various data processing technologies were used. Personal computers were found to be invaluable for tracking and reporting manpower, installation and unit rates, and for producing weekly budget reports. The mainframe was used for batch processing the PCS reports and a mini-computer was used for performing Project-2 construction network analysis of the critical path and schedule float.

Overall, the Project Control System was an extension of the Management philosophy. The system promoted participation, communication, commitment and accountability, through dedicated adherence to a process. At no time was the handling of data allowed to become a major issue or end product.

INDEPENDENT REVIEW TEAM (IRT)

One effective way to achieve an on-going critique (sometimes called a "sanity check") of the project is to establish an Independent Review Team. At Seabrook, an IRT Manager with a six man multi-discipline team of contractors was organized and reported to the VP of Quality Programs. Members were selected to represent Engineering, Construction, QA, Startup, Operations, and various other technical disciplines as required for special reviews. A report and an action item matrix was prepared with each review for follow-up of corrective

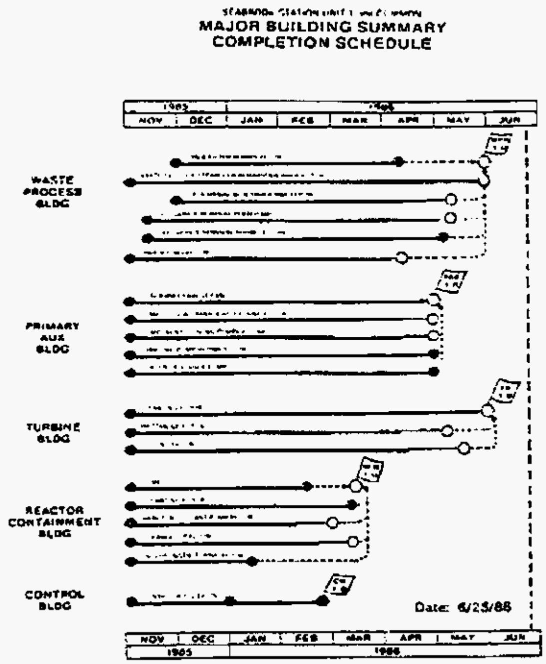


Chart 8

Florida Power & Light Company
Quality Improvement Program Implementation Steps

1. Management Commitment
2. Quality Improvement Team
3. Management Orientation & Training
4. Economic Analysis
5. Root Cause Identification
6. Corrective Action
7. Awareness
8. Recognition

Chart 10

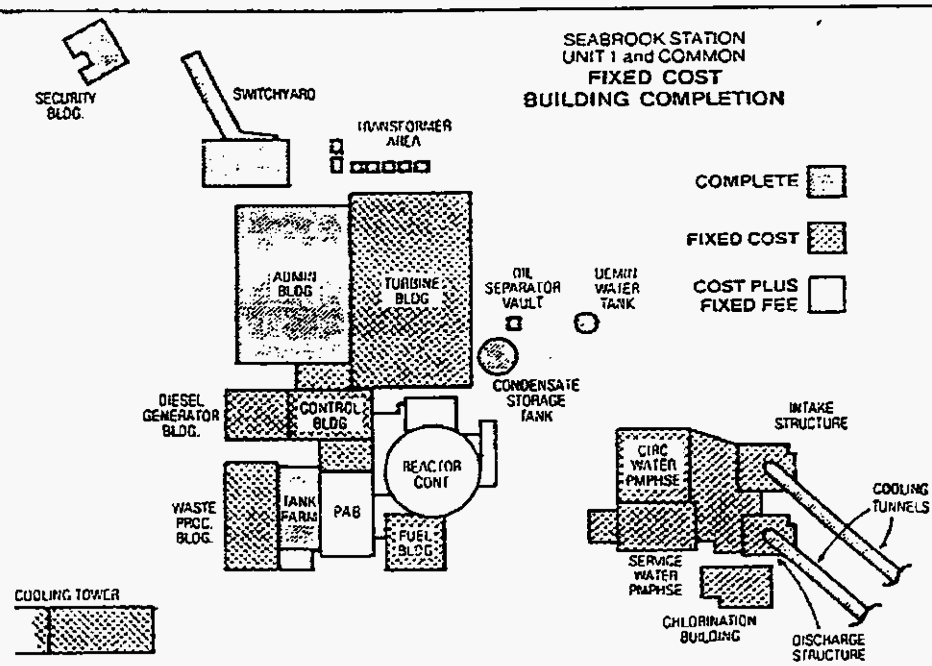


Chart 9

action recommendations. Emphasis was placed on identifying individuals responsible for follow-up. These internal reviews provided many benefits, including; helping to prepare for NRC audits, avoiding costs associated with implementing regulatory changes and controlling staffing levels.

The effectiveness of the IRT was enhanced by selecting a highly qualified team which brought experience from other projects and avoided a tendency to reinvent the wheel. The project organization learned to expect a quality job which led to acceptance of the IRT's recommendations. One early priority of the IRT was to analyze the Engineering Change Authorization (ECA) process in the field. This process included the engineering evaluation of construction initiated changes. Implementation of IRT recommendations to place qualified engineers in different construction locations enabled on-the-spot analysis and sign-off which reduced the ECA turnaround from an average of eleven days to one day and expedited about 500 changes per month.

IRT studies and resulting organizational follow-up contributed to an excellent SALP (Systematic Assessment of Licensee Performance) rating of Seabrook by the NRC in March, 1986. The project received top ratings in all but one of six functional areas and a two (good and improving) in the other area. No areas were identified by the NRC as needing improvement.

The IRT helped to reinforce the value of a second opinion as a way to critique all major decisions and provide prudency assurance. The independent review or critique, can help you assess where you are and where you're going; and, if properly utilized, will most certainly increase the probability of success.

CONCLUSION

Adherence to the management approach described herein contributed to the success in constructing St. Lucie 2 and completing Seabrook I and satisfying prudency reviews. Consciously establishing a philosophy for which everyone must "sign up" will motivate the project personnel to meet the established objectives.

A perfect project is not necessarily comprised of all perfect parts. Objectives must always be clearly in focus and the team must understand your philosophy. For example, a purchasing manager must realize that the lowest bidder is not the best choice, if he is unable to meet the required delivery schedule. The engineering manager must similarly look for technical solutions that will work and satisfy the requirements at minimum cost, not the ones that are technically perfect. Innovative methods and trade-offs are required in many areas every day if the project is to meet overall objectives and schedule milestones, given monetary constraints.

The most important action for the owner of a large project is to be in the lead. For Architect Engineering/Constructor firms to be successful, they must have strong owner involvement and support. This involvement builds trust, confidence and develops a partnership bond needed to confront the many internal and external obstacles facing achievement of project goals.

Above all, the Project Manager must be a leader by creating an atmosphere for good communications and being relentless in the application of his philosophies and beliefs. These beliefs have been successfully applied to both the St. Lucie and Seabrook Projects.

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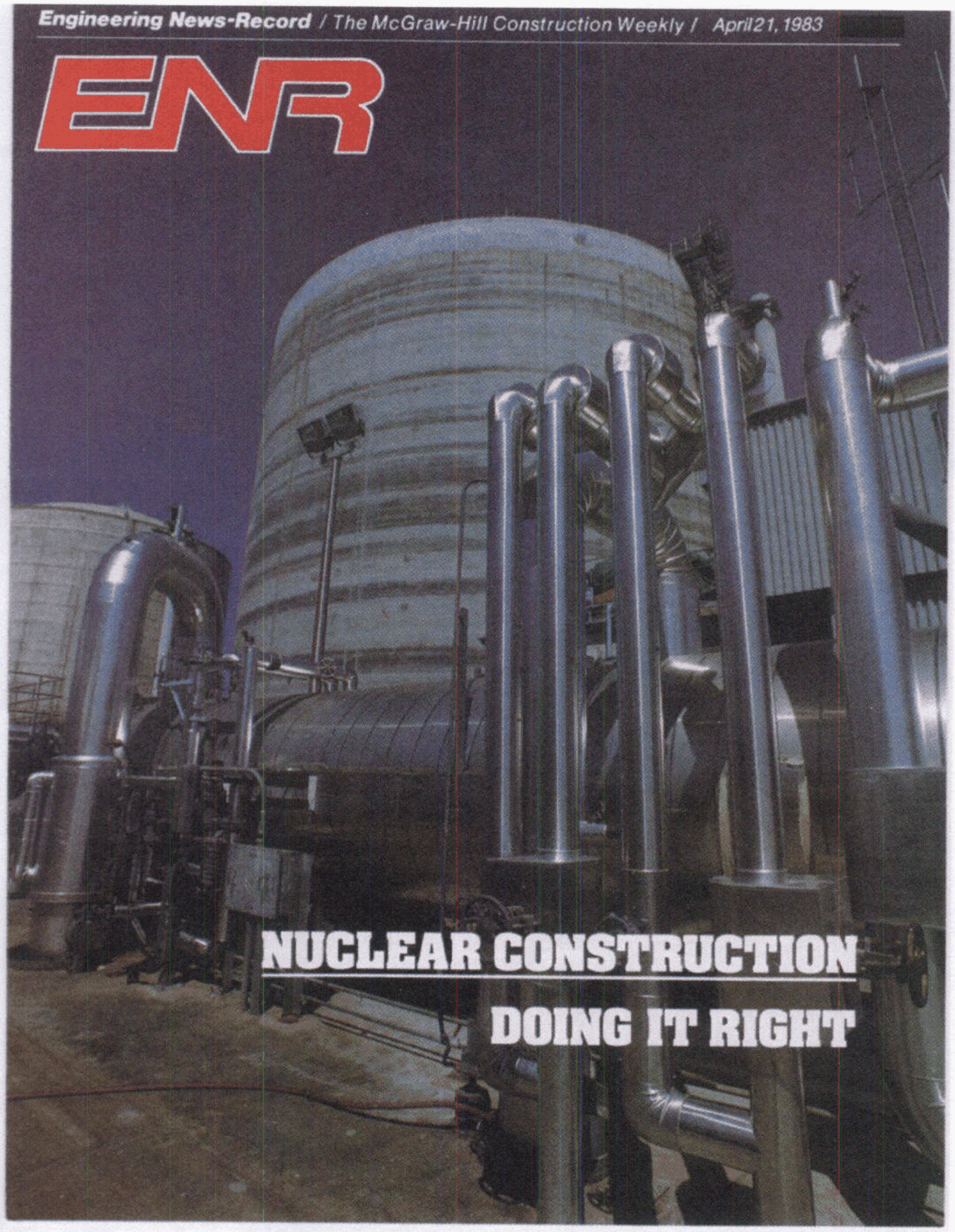

Engineering News-Record / The McGraw-Hill Construction Weekly / April 21, 1983
ENR
NUCLEAR CONSTRUCTION
DOING IT RIGHT

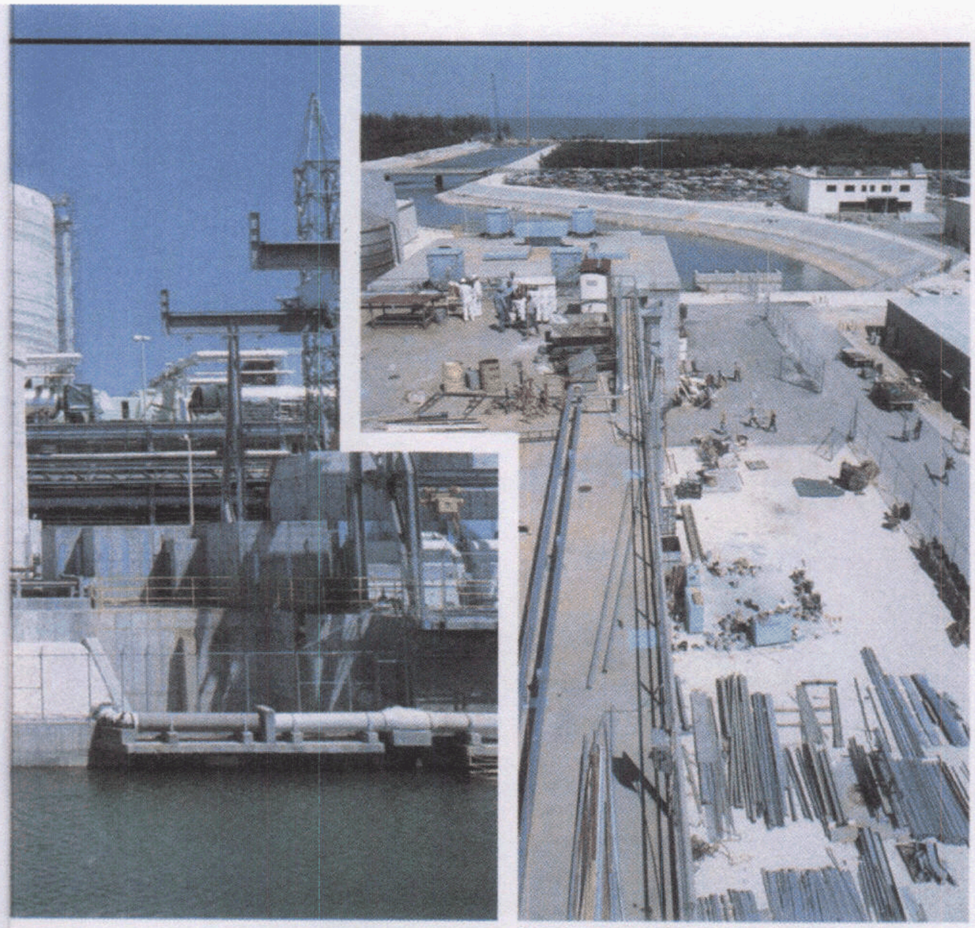
Six-year schedule met by Florida Power & Light and Ebasco at St. Lucie two sets an industry benchmark.

NUCLEAR CONSTRUCTION

In the frustrating world of nuclear construction, the losers get all the attention. If it's not the five construction-quality-assurance failures cited by Nuclear Regulatory Commission Chairman Nunzio Palladino in his Dutch-uncle lecture last year, it's the WPPSS fiasco in Washington State, Three Mile Island, scheduling foul-ups and the embarrassing cost spiral that dominate the headlines.

But while most nuclear utilities and contractors have been busy explaining their problems, a tightly knit team working on an island off the east coast of Florida has been busy solving theirs. The result at St. Lucie unit two will be completion of Florida Power & Light Co.'s 810-Mw pressurized-water reactor, at a cost of $1.42 billion, in June, exactly six years after its construction permit was issued.

That's a benchmark in the nuclear construction business these days. By comparison, the lead times for the 10 plants completed since the beginning of 1978—one before the Three Mile Island accident in March, 1979, and the rest since 1980—have stretched out from 96 to 144 months. "When you compare this job to the rest of the business, we're number one," says William B. Derrickson, project general manager for FP&L, "and we can still do better."



Oceanside plant gets finishing touches for full power in June.

-DOING IT RIGHT

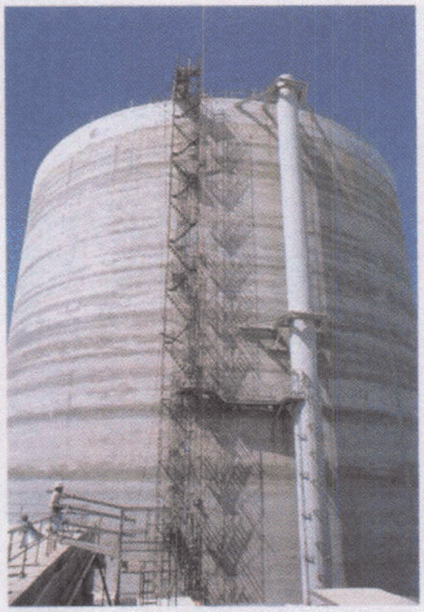
Of the plants under construction now, Arizona Public Service Co.'s Palo Verde unit one, a 1,270-Mw PWR designed and being built in the desert west of Phoenix by Bechtel Power Corp., San Francisco, is running a respectable second to St. Lucie, where Ebasco Services Co., Inc., New York City, is handling design and construction. Palo Verde's construction permit was issued in May, 1976, and full power is scheduled for the Combustion Engineering reactor this August, seven years and two months later.

In many ways, St. Lucie two was set up for speed:

- It is a near twin of unit one, an 810-Mw Combustion Engineering reactor, completed by Ebasco and FP&L on a 78-month schedule—from construction permit to commercial operation—in December, 1976.
- Design of the second unit was nearly 75% complete before the start of construction, and site preparation actually began in June, 1976, under a limited work authorization. That was suspended by the Nuclear Regulatory Commission (NRC) four months later, however, because a new rule required study of other potential sites.
- FP&L was one of the early entrants in the nuclear power business with its two Bechtel-built Turkey Point plants south of Miami, which were brought on line in 1972 and '73, plus St. Lucie one, so it has experience building nuclear plants.
- Where some oil-dependent utilities jumped into the nuclear era with both feet, FP&L held back some, canceling two

planned 1,140-Mw reactors in 1976. As a result, except for replacing the steam generators in the two Westinghouse steam supply systems at Turkey Point and TMI safety backfits at St. Lucie one, FP&L's nuclear staff has been able to concentrate heavily on St. Lucie two construction.

- Because construction started just as unit one was being completed, close to 80% of the skilled laborers and half of the nonmanual staff stayed on to build the second plant.
- Where Seabrook had its Clamshell Coalition and Diablo Canyon its Abalone Alliance storming the fences, only a few green sea turtles have shown much curiosity about the construction at St. Lucie. The station is located 45 miles north of West Palm Beach in a remote area on Hutchinson Island, near the retirement communities around Fort Pierce. The generally conservative residents in the area have supported the plant.
- Demand growth for electricity in Florida had been growing at 11 to 13% a year in the early 1970s. That has dropped to about 3.8% a year in FP&L's service area, but it is still well above national averages, so there has never been any relaxing on the critical path toward completion. And, while most utilities have found themselves in a cash bind—mainly because of ambitious construction programs during a period of high interest rates and slack demand growth—FP&L has maintained its fiscal fitness over the years.



Containment shield wall slipformed in 16½-day pour.

The true path. At St. Lucie one, says Derrickson, "we discovered what turned out to be the real critical path." Despite industry experience to the contrary, he figures that six years "is what it ought to take to do this job. In 1977, we looked at the manhours, the work and the logic and came up with a 65-month schedule for unit two that put the start of fuel loading on Oct. 28, 1982."

Crews were bolting the head on the loaded reactor core last week, and Derrickson expects to be at 5% power in three weeks and at full power in mid-June. The slip in the schedule is mainly due to post-TMI safety backfits and other design changes required by NRC or desired by FP&L. To hold slippage to a minimum, a number of changes not required by NRC or for operation of the plant—a condensate polishing system, for example—have been held over for backfitting before and during the reactor's first refueling outage in early 1985. Derrickson estimates the cost of that work at about $46 million.

An important element in making the start-up target was the all-out effort made by FP&L, Combustion Engineering and Ebasco engineers in negotiations with NRC over the final safety analysis report. Getting the safety checkoff needed for an operating license generally takes about 30 months. It took nine months—and more than 40 across-the-table meetings between NRC and project technical staffs—to get the regulatory blessing for St. Lucie two.

"Normally we go back and forth with formal letters asking new questions and requesting detailed explanations of answers," says Victor Nerses, NRC senior project manager for St. Lucie two. "We cut through a lot of misconceptions and misunderstandings by sitting across the table. Our engineers were talking with their engineers and we came away understanding what everyone was talking about."

Also, the negotiations were conducted, for the most part, without lawyers. "I'm suspicious of lawyers," says H. James Dager, vice president of engineering, project management and construction for FP&L. "Once you put things in their hands, you get a lot of legalese and an adversary relationship develops."

Power equipment checked out in start-up campaign.

Construction attack. Completing the construction and licensing work in 72 months—six months faster than unit one—is no mean achievement. Even though the two units are twins, unit two is much beefier. It is designed to meet higher seismic and missile-impact criteria, for example, and all updated design requirements. In materials alone, that has resulted in placement of an additional 15,000 cu yd of concrete, 1,000 tons of structural steel, 1 million ft of cable, 7,000 ft of large diameter piping and 4,400 more welds on unit two.

A number of scheduling and construction innovations used at St. Lucie two helped crews to get more work done faster. To excavate and pour the foundation mat for the reactor containment building without affecting the operation of unit one only a few hundred feet away, Ebasco designed what it claims is the first nuclear-safety-class cofferdam. The 180-ft-dia circular cell was placed by driving 500 tons of sheetpiling in 72-ft lengths using electrical vibratory hammers. The sheets were braced with internal compression rings made up of 900 tons of wide-flange beams, 36 in. deep, that were installed every 5 ft on vertical centers.

After extensive preparations, the concrete containment shield wall for the reactor was slipformed in a continuous pour lasting 16½ days. The cylindrical, heavily reinforced concrete wall, 3 ft thick, 191 ft high and 74 ft in diameter, required 10,000 cu yd of concrete placed around hundreds of embedded conduits, grounding cables and anchor bolts. Conventional step-forming of shield walls can take from 12 to 18 months.

To get an early start on the time-consuming concrete work inside the reactor containment, Ebasco chose to heat-treat the lower sections of the steel containment vessel by capping it with a temporary diaphragm rather than wait until the permanent steel dome could be placed on the top of the vessel. The lower portion of the vessel where the plates are thickest must be heated in place to relieve stress that builds up during erection. The thinner dome plates do not need heat treatment.

FP&L manager Derrickson

"I could do one more of these in my life and then I'd be ready for a nice soft desk job," says the 43-year-old project chief. "Utilities have to run the show in this business and the plants have to be built to operate."

Construction of the reactor auxiliary building was done in a phased process that let craftsmen get started installing the control room, electrical cable vault and other critical equipment while other sections of the structure were still being built. The building went up in a stair-step fashion. As each elevation was completed, all major equipment for that level was lifted in before the roof was placed.

Thanks, I needed that. During construction of the auxiliary building, on Sept. 3, 1979, Hurricane David hit the site, knocking down a 150-ton derrick being used to lift materials into the containment and auxiliary building. The 180-ft tower, 250-ft mast and 200-ft boom were destroyed. But more important, large sections of the auxiliary building were badly damaged. The initial estimate of lost time to repair the damage and replace equipment was 13 weeks.

After the initial shock, however, the effect of the accident was to shake the project up and put everyone into high gear. "The derrick collapse was probably the turning point in the project," says Leo Tsakiris, Ebasco project manager. "It pulled everyone together."

Ebasco engineers developed repair procedures and expedited orders for replacement equipment. Crews and supervisors put in additional overtime to make up for hours spent on repair projects. By the following November, the 13-week loss on the critical-path schedule was made up.

The key ingredient in the rebound from the crane collapse and in overcoming all other construction problems, Tsakiris says, has been the open and easy communication between his staff and utility managers. The peculiar, matrix-within-a-matrix site organization is partly responsible. Ebasco's construction supervisors manage craft workers and subcontractors, making sure that schedules are met. Where FP&L wants direct control and responsibility—in the areas of quality assurance, cost control, contract administration and start-up, for example—its man heads up the mostly Ebasco staff. In other areas, Ebasco managers take the lead. Everyone, including Tsakiris, ultimately reports to Derrickson, however.

The communication is built on trust. "If Bill tells me go ahead, that's all I need," says Tsakiris, "I don't have to keep looking over my shoulder all the time." And the trust is built on the long association between Ebasco and FP&L managers, many of whom have moved up the ranks together on the St. Lucie station and other FP&L powerplants. Derrickson and Tsakiris, for example, have been associates for 13 years. "We've been working together since we were kids," Tsakiris quips. "We each know what the other is going to say before he says it."

Another factor in the successful construction effort, says R. W. Zaist, Ebasco project superintendent, is the return to basics at St. Lucie two. "Plan your work, get the material here and give the crews solid guidance. A lot of people have gotten overwhelmed with the next best computer system or management philosophy. What happens is that all the managers and submanagers get so busy with their own business that they forget the guy in the field."

Ebasco manager Tsakiris

"There may be some people who see a profit from delays. That's never been our way," he says, adding, "NRC takes the brunt of the blame for delays, but they've been made a scapegoat in a lot of situations."

Utility control. Where a number of utilities have handed management of nuclear projects over to their architect-engineers, FP&L managers in Miami and at the site took control of St. Lucie and assumed responsibility for their decisions. "If anybody's got a problem on this job, everybody's got a problem," says Derrickson.

The most important exercise of that control has come in FP&L's aggressive start-up program at St. Lucie two. Plant operations staff were brought in during 1979, 35 months prior to the scheduled fuel-load date, to begin accepting systems or components of systems so they could be tested and fixed if necessary. The start-up crew was gradually increased to 64 operations technicians, who assumed more and more control of construction as work progressed toward completion. Eventually, FP&L's fine-tuners took over project management, creating some tension between construction and start-up staffs. But, as Tsakiris says, "It's good tension."

A total of 488 separate systems were identified and scheduled for turnover in a prioritized sequence to meet major project milestones. To support that effort, a computerized punch list of components and work items was developed—including a checklist of inspection schedules for the resident NRC inspector—to keep track of daily targets.

FP&L's aggressive style contrasts sharply with some other utilities that have handed management of their nuclear projects to architect-engineering firms. A number of those plants are in trouble now, Derrickson points out. "You can build all the fancy domes and use the best models and computer programs in the world," he says, "But if the utility doesn't get involved in start-up and make sure the plant is built to run right, all that fancy stuff doesn't make a hoot of difference." ■

WBD-5

Derrickson Testimony

Nuclear Industry Chronology 1968 to 1985

Exhibit 5

1954	Atomic Energy Act Passed creating the Atomic Energy Commission (AEC)
1960	First commercial nuclear power plant, Yankee Rowe, begins operation
1968	Construction begins on Turkey Point Units 3 and 4
1969	American National Standards Institute (ANSI) issues Standard B31.7, "Nuclear Power Piping" replacing the previously used piping code B31.1.
1970	AEC issues 10 CFR 50, Appendix B, Quality Assurance Requirements for Nuclear Power Plants
1970	National Environmental Policy Act (NEPA) signed into law.
1970	Construction begins on St. Lucie Unit 1
1970	Occupational Safety and Health Administration (OSHA) created
1970 - 1972	AEC issues initial 32 Safety (later Regulatory) Guides detailing technical methods acceptable to the AEC staff. By 2010, over 250 such guides would be issued.
1971	United States Court of Appeals for the District of Columbia rules that the AEC must consider environmental issues when issuing a license (Calvert Cliffs decision).
1971	ASME Boiler and Pressure Code Section III revised.
1971	IEEE 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations" issued replacing (and expanding upon) earlier IEEE – 279 - 1968
1972	AEC holds hearings on the effectiveness of Emergency Core Cooling Systems (ECCS). Hearings lead to changes in licensing criteria (10 CFR 50, Appendix K).
1972	AEC issues Safety Guide 29, "Seismic Design Classification." [This guide along with Regulatory Guide 1.60, "Design Response Spectra for Seismic Design of Nuclear Power Plants," issued in 1973, changed the manner in which the seismic design basis for nuclear power plants was determined.
1972	AEC issues Regulatory Guide 1.70, "Standard Format and Content of Safety Analysis Reports for Nuclear Power Plants (LWR Edition)" delineating and expanding the information requirements to be provided in Safety Analysis Reports submitted with License Applications.
1972	Turkey Point Unit 3 completed
1973	Turkey Point Unit 4 completed
1974	Energy Reorganization Act of 1974 enacted. AEC disbanded and Nuclear Regulatory Commission (NRC) formed to regulate the nuclear power industry. Energy Research and Development Administration (ERDA) created to assume responsibility for all energy-related R&D.

1974	Regulatory Guide 1.75, "Physical Independence of Electric Systems" issued changing and defining the requirements for separation of redundant electrical and I&C systems. Plants under construction redesigned and plants in service modified.
1974	WASH 1400, "Nuclear Safety Study" (Also known as the Rasmussen Report) issued. First probabilistic review of nuclear power plant safety
1974	IEEE issues standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations";
1974	IEEE issues Standard 344-1987, "IEEE Recommended Practice for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations"
1974	IEEE issues Standard 384-1974 "Criteria for Independence of Class 1E Equipment and Circuits"
1975	Major fire at TVA's Browns Ferry Nuclear Plant in Alabama
1975	Regulatory Guide 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants," issued requiring additional monitoring equipment.
1975	Regulatory Guide 1.101, "Emergency Planning and Preparedness for Nuclear Power Reactors," issued requiring additional planning to address anticipated emergencies.
1975	NRC issues 10 CFR 50, Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable" for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents" (ALARA) establishing the need for and basis of licensees programs to limit radiation dosage to workers and public.
1975	NRC issues NUREG 75/087 (later known as NUREG 0800) "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR Edition" detailing and expanding the information that the NRC regulatory staff will require during the performance of their regulatory review of license applications.
1976	St. Lucie Unit 1 completed
1977	Construction begins on St. Lucie Unit 2
1977	NRC issues 10 CFR Part 21, "Reporting of Defects and Non-compliances"
1978	Design error related to calculation of piping stress analysis performed by Stone and Webster Engineering Corporation (SWEC) discovered at North Anna station. All other SWEC designed plants (i.e., Beaver Valley, Surry, Fitzpatrick, Nine Mile Point, Maine Yankee) required to re-perform analysis. All other PWR plants required (Inspection and Enforcement Bulletin 79-07) to verify that similar errors did not exist in their design.
1979	Accident at Three Mile Island Nuclear Plant Unit 2 near Harrisburg, PA. (March 28)
1979	NRC issues Inspection and Enforcement Bulletin (IEB) 79-14, "Seismic Analysis for As-Built Safety-Related Piping Systems" requiring all plants to re-evaluate and validate the seismic design of their safety system piping.
1979 - 1980	NRC issues multiple reports detailing changes required as a result of the accident at TMI

NUREG 0585 – "TMI – Lessons Learned Task Force – Final Report"
NUREG 0654 – "Criteria for Protective Action Recommendations for Severe Accidents"
NUREG 0660 – "NRC Action Plan Developed as a Result of the TMI Accident" (1979)
NUREG 0696 – "Functional Criteria for Emergency Response Facilities"
NUREG 0737 – "Clarification of TMI Action Plan Requirements"

1980 NRC issues 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities" expanding the requirements for detailed Emergency Plans and coordination with federal, state and local authorities.

1981 NRC issues 10CFR 50, Appendix R, "Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979" detailing and expanding requirements associated with fire protection systems.

1982 Nuclear Waste Policy Act of 1982 (NWPA) signed into law requiring the Department of Energy to establish a national high level nuclear waste repository. [Law was subsequently revised in 1987]. Failure of the DOE to act in a timely manner has created the need for on-site nuclear waste storage facilities.

1983 St. Lucie Unit 2 completed

1986 Accident at Chernobyl Nuclear Plant in the Ukraine

1986 NRC issues Regulatory Guide 5.65, "Vital Area Access Controls, Protection of Physical Security Equipment, and Key and Lock Controls" expanding nuclear plant security requirements.

1988 NRC issues 10 CFR 50.109, "Backfitting Rule" establishing the basis for post-licensing modifications that need to be made to plants already in operation.

1989 NRC issues 10 CFR Part 52, "LICENSES, CERTIFICATIONS, AND APPROVALS FOR NUCLEAR POWER PLANTS" addressing the concept of issuing combined construction and operating licenses.

1991 NRC issues 10CFR50.65 "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" ("Maintenance Rule"). Rule becomes effective July 1996.

1996 Deficiencies related to plant documentation and design bases identified at the Millstone Plant in Connecticut result in the need for all nuclear plants to recertify their design and licensing bases. [Letter from J. Taylor, EDO, NRC, to all nuclear utility CEOs, October 9, 1996.and NEI 97-04, "Design Bases Program Guidelines,"]

2001 Events of September 11, 2001

Post-2001 NRC upgrades nuclear plant security requirements.

2009 NRC issues Regulatory Guide 5.74, Managing the Safety/Security Interface" and Regulatory Guide 5.75, "Training and Qualification of Security Personnel at Nuclear Power Reactor Facilities"

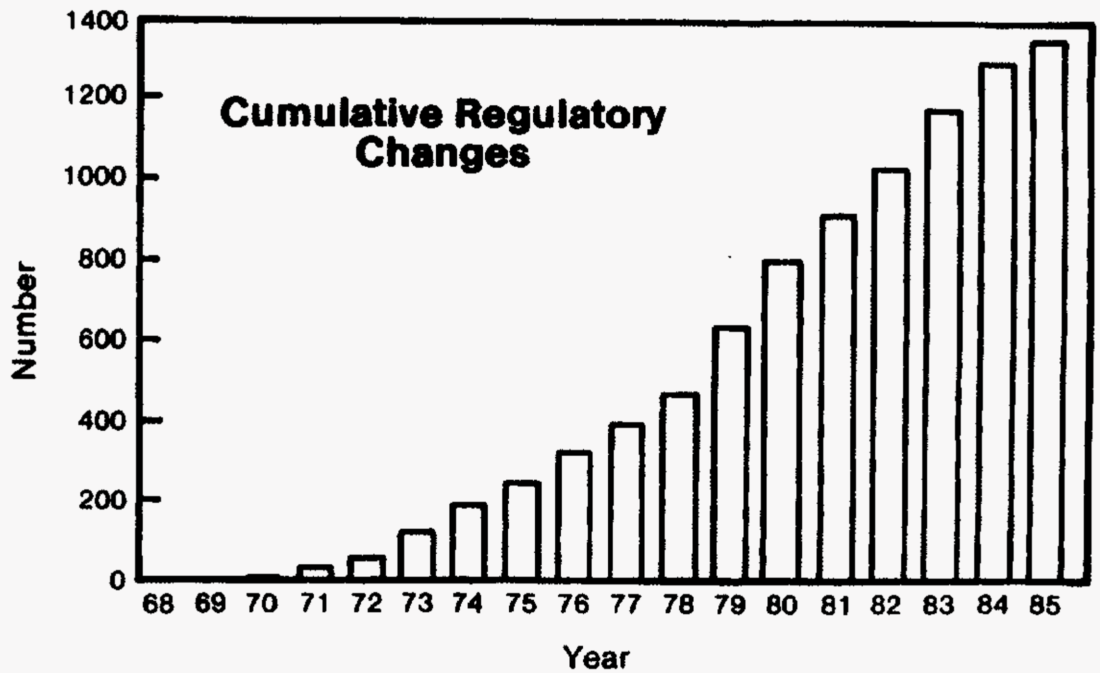
2010 NRC issues Regulatory Guide 5.71, "Cyber Security Programs for Nuclear Facilities"

WBD-6

Derrickson Testimony

Exhibit 6

Cumulative Regulatory Changes 1968 to 1985



WBD-7

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM B. DERRICKSON

DOCKET NO. 110009-EI

March 1, 2011

LIST OF PERSONS WHITH WHOM THE EPU PROJECT WAS DISCUSSED

Abbott, Liz	Director, EPU Licensing & Regulatory Interface
Beisler, Bruce	Manager State Regulatory
Delowery, Mike	EPU Site Director, PSL
Fata, Alan	EPU Site Director, PTN
Fleetwood, Don	Director, EPU Project Controls
Jones, Terry	Vice President, EPU
Katz, Alan	EPU Site Project Manager, PTN
Reuwer, Steve	EPU Implementation Owner, South
Sipos, Richard	EPU Site Project Manager, PSL

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

DIRECT TESTIMONY OF WILLIAM B. DERRICKSON

DOCKET NO. 110009-EI

March 1, 2011

EXHIBIT 8

DOCUMENTS REVIEWED

1. EPPI-100R3-Project Instructions
2. EPPI-140R9-Roles and Responsibilities
3. EPPI-150R1-NBO Interface and Variance Reporting
4. EPPI-160R2-EPU Formal Correspondence
5. EPPI-170R2-Time & Exp. Reporting for Nextera support
6. EPPI-180 R1-EPU Nuclear Cost Recovery
7. EPPI-220R3-PR Funding Request and Sole Source Justification
8. EPPI-230R6-EPU Project Invoice Processing Instructions
9. EPPI-240R3-Contract Compliance
10. EPPI-300R9-EPU Project Change Control
11. EPPI-301R00-EPU Forecast Variance AND Trends
12. EPPI-310R5 Maintenance, Development and Update of schedules
13. EPPI-320R2 Cost Estimating
14. EPPI-340 R3-EPU Project Risk Management Program
15. EPPI-345R00-EPU LAR Engineering Risk Management
16. EPPI-370R3-EPU FPL Accrual Process
17. EPPI-380R1-EPU Project Self Assessment
18. EPPI-445R0-Att.3 Process Flow Chart (St. Lucie) Rev. C
19. EPPI-445R0-Att.3 Process Flow Chart (Turkey Point) Rev. B
20. EPPI-445R0-EPU Test Guidelines
21. EPPI-445R0-Test Guidelines-Attachments
22. EPPI-520R1-Project Personnel Training Requirements
23. EPPI-560R3-EPU Project Qualification Guidelines
24. EPPI-610R2-EPU License Amendment Writers Guide

25. EPPI-810R2-PSL Severe Weather Preps
26. EPPI-820R00-EPU Project Environmental Control Program-PSL
27. EPPI-910R1-PTN Severe Weather Preparation
28. EPU Contract PO Funding Request-Nextera
29. PSL Metrics Package (10-10-27)
30. PTN Metrics Package (10-10-27)
31. FPL Bechtel Leadership Mtg. 10.6.2010
32. TCM-GAM-00287 Package 25489-000
33. Juno EPU Organization Chart
34. Turkey Point EPU Site Organization 8.24.2010
35. St. Lucie EPU Site Organization 7.10.2010
36. NEXTERA 2009 10K
37. Nextera 2010 Third Quarter Financial Report
38. PTN Risk Register 10.10.2010
39. PSL Risk Register 11.11.2010
40. PTN EPU Owner Productivity Analysis 10-17-10
41. PSL Performance Indicators October 2010
42. PSL Performance Indicators for Week Ending 10.31.2010
43. Monthly Combined EPU Metrics 11.5.2010
44. EPU 3R25 Outage Report 10.22.2010
45. PSL EPU Earned Value Report 11.5.2010
46. Presentation to the Executive Steering Committee 7.25.2009 St. Lucie
47. Presentation to the Executive Steering Committee 7.25.2009 Turkey Point
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51. Presentation to the Executive Steering Committee 5.26.2010
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53. Presentation to the Executive Steering Committee 7.27.2010
54. Extended Power Uprates CNO Update St. Lucie and Turkey Point 5.7.2010
55. Extended Power Uprates CNO Update St. Lucie and Turkey Point 5.14.2010
56. Extended Power Uprates CNO Update St. Lucie and Turkey Point 6.21.2010
57. Extended Power Uprates CNO Update St. Lucie and Turkey Point 7.12.2010

58. Extended Power Uprates CNO Update St. Lucie and Turkey Point 8.3.2010
59. Extended Power Uprates CNO Update St. Lucie and Turkey Point 8.16.2010
60. Extended Power Uprates CNO Update St. Lucie and Turkey Point 8.31.2010
61. Extended Power Uprates CNO Update St. Lucie and Turkey Point 9.9.2010
62. Extended Power Uprates CNO Update St. Lucie and Turkey Point 9.14.2010
63. Extended Power Uprates CNO Update St. Lucie and Turkey Point 9.24.2010
64. Extended Power Uprates CNO Update St. Lucie and Turkey Point 10.11.2010
65. Review of FPL's Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects July 2009
66. Review of FPL's Project Management Internal Controls for Nuclear Plant Uprate and Construction Projects July 2010
67. PSLEPUAPRMOPRFinal
68. PSLEPUAUGMOPRFINAL
69. PSLEPUFEBMOPR10-03-10final
70. PSLEPUJANMOPR10-02-10DFinal
71. PSLEPUJulyMOPRFINAL
72. PSLEPUJuneMOPRFINAL
73. PSLEPUMARMOPRfinalrev1
74. PSLEPUMayMOPRfinal
75. PSLEPUOctFINAL
76. PSLEPUSeptFINAL
77. PSLPTNEPUNucAPRKeyIssuesFinal
78. PSLPTNEPUNucAUGKeyIssuesFinal
79. PSLPTNEPUNucFEBKeyIssuesFinal
80. PSLPTNEPUNucJANKeyIssuesFinal
81. PSLPTNEPUNucJULYKeyIssuesFinal
82. PSLPTNEPUNucJUNEKeyIssuesFinal
83. PSLPTNEPUNucMARKeyIssuesFinal
84. PSLPTNEPUNucMayKeyIssuesFinal
85. PSLPTNEPUNucOCTKeyIssuesFinal
86. PSLPTNEPUNucSeptKeyIssuesFinal
87. PTNEPUAPRMOPRFinal

88. PTNEPUAUGMOPRFINAL
89. PTNEPUFEBMOPR10-03-10final
90. PTNEPUJANMOPR10-02-10DFinal
91. PTNEPUJulyMOPRFINAL
92. PTNEPUJuneMOPRFINAL
93. PTNEPUMARMOPRfinalrev1
94. PTNEPUMayMOPRfinal
95. PTNEPUOctFINAL
96. PTNEPUSeptFINAL
97. Samples of EPU scope changes and forecast variances
98. EPU Project Turkey Point 2010 major decisions
99. EPU Project St. Lucie 2010 major decisions
100. Turkey Point Bechtel Scope Specification SPEC-M-156
101. St. Lucie Bechtel Scope Specification SPEC-M-157
102. Samples of EPU training records as required by EPU procedure EPPI-560
103. Samples of self assessment reports as required by procedure EPPI-380
104. PTN3R25 and 4R26 EPU Outage Details
105. 201005_079_0365_PTN EPU Accruals
106. 201007_079_0358_EPU PSL Accruals
107. Samples of EPU budget summaries
108. Samples of engineering risk registers
109. Samples of EPU accrual worksheets
110. Samples of St. Lucie and Turkey Point accruals

WBD-9

Exhibit 9

Photographs of the Turkey Point Congestion

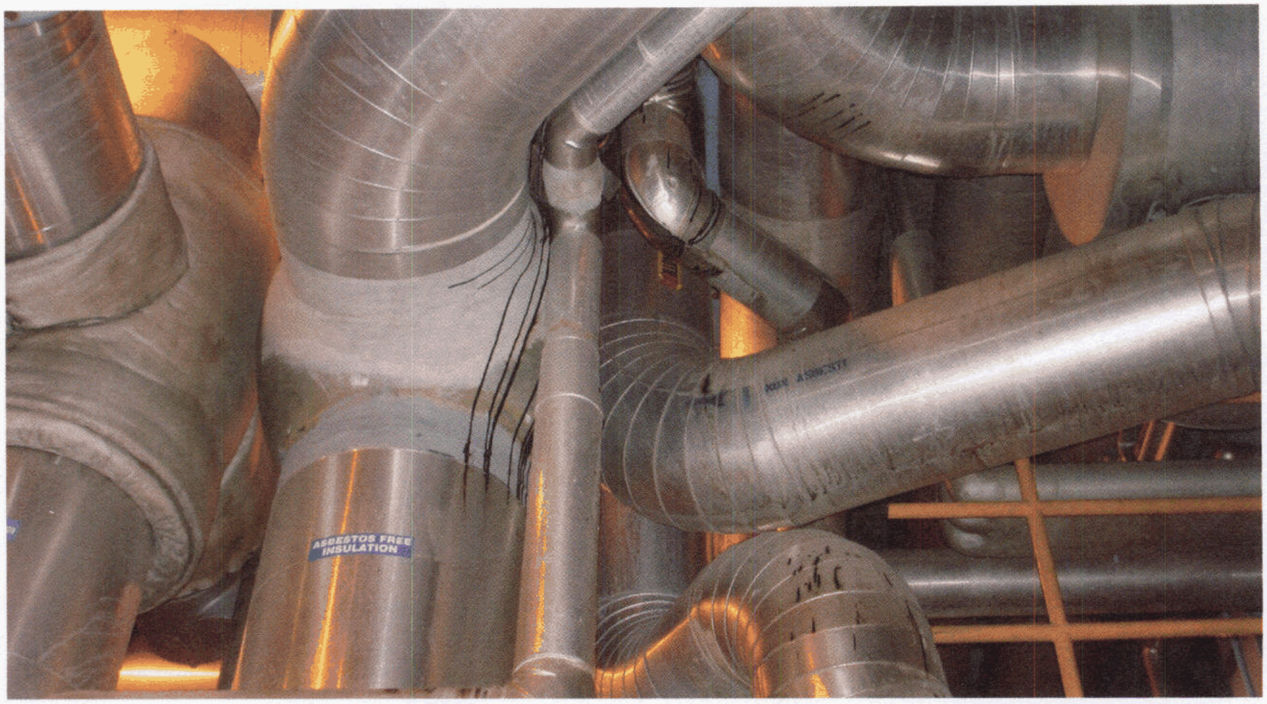


Photo 1 Turkey Point Congestion

Photo 2 Turkey Point Congestion

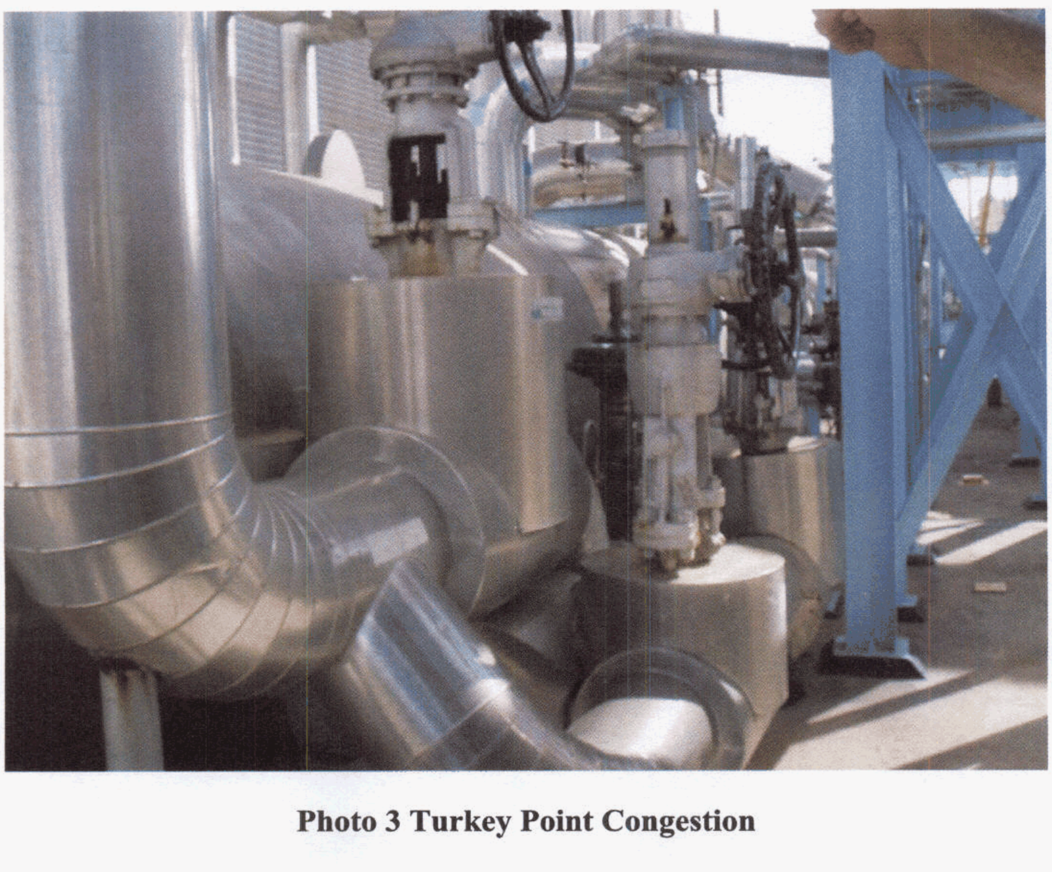
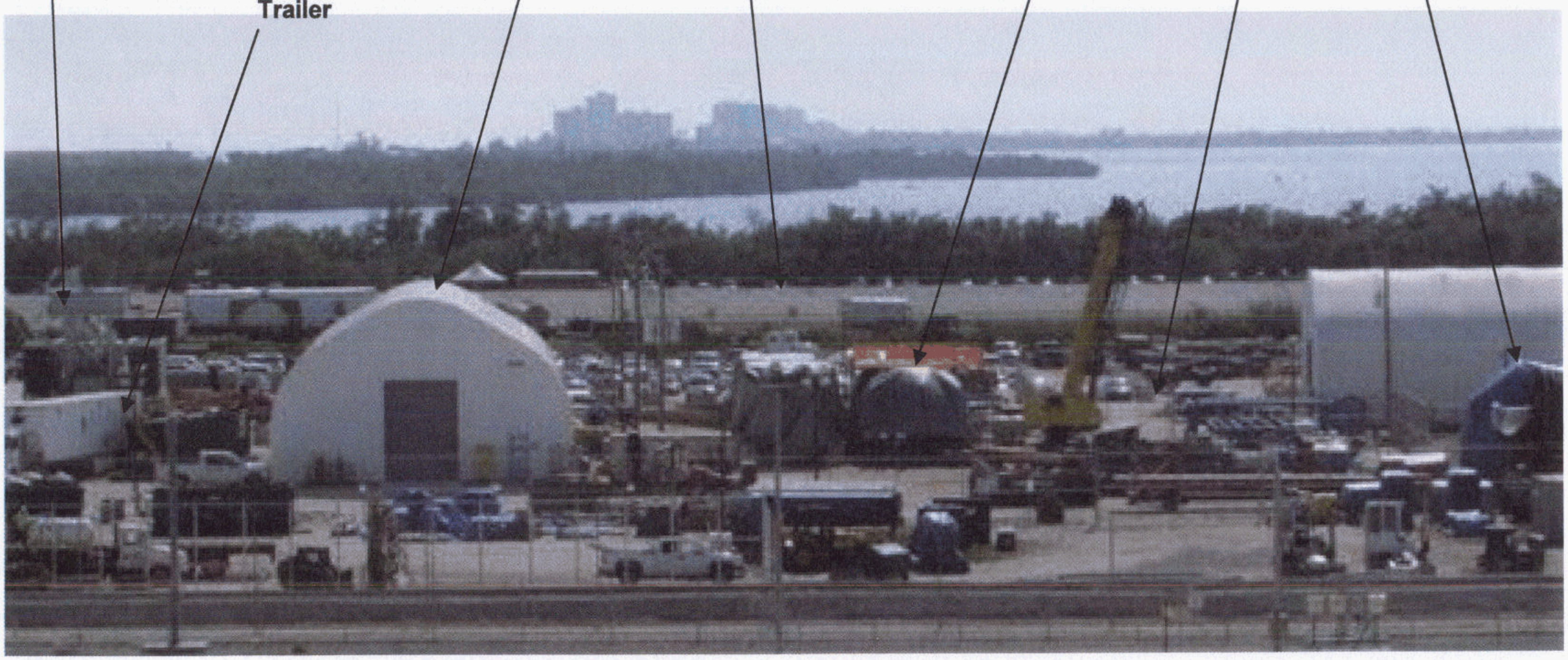


Photo 3 Turkey Point Congestion

Photo 4 Turkey Point Congestion

WBD-10

St.Lucie Extended Power Uprate
South Laydown Area



Docket No. 110009-EI
St. Lucie Photographs
Exhibit WBD-10,Page 1 of 4

St. Lucie Unit 2 Turbine Deck

Generator Rotor being removed and lifted to transporter

Scaffolding around plant components

Temporary Offices and Material & Tooling Storage

Docket No. 110009-EI
St. Lucie Photographs
Exhibit WBD-10,Page 2 of 4

St. Lucie Turbine Deck

Low Pressure Turbine w/ Rotors removed

Environmental Structure over the Main Generator

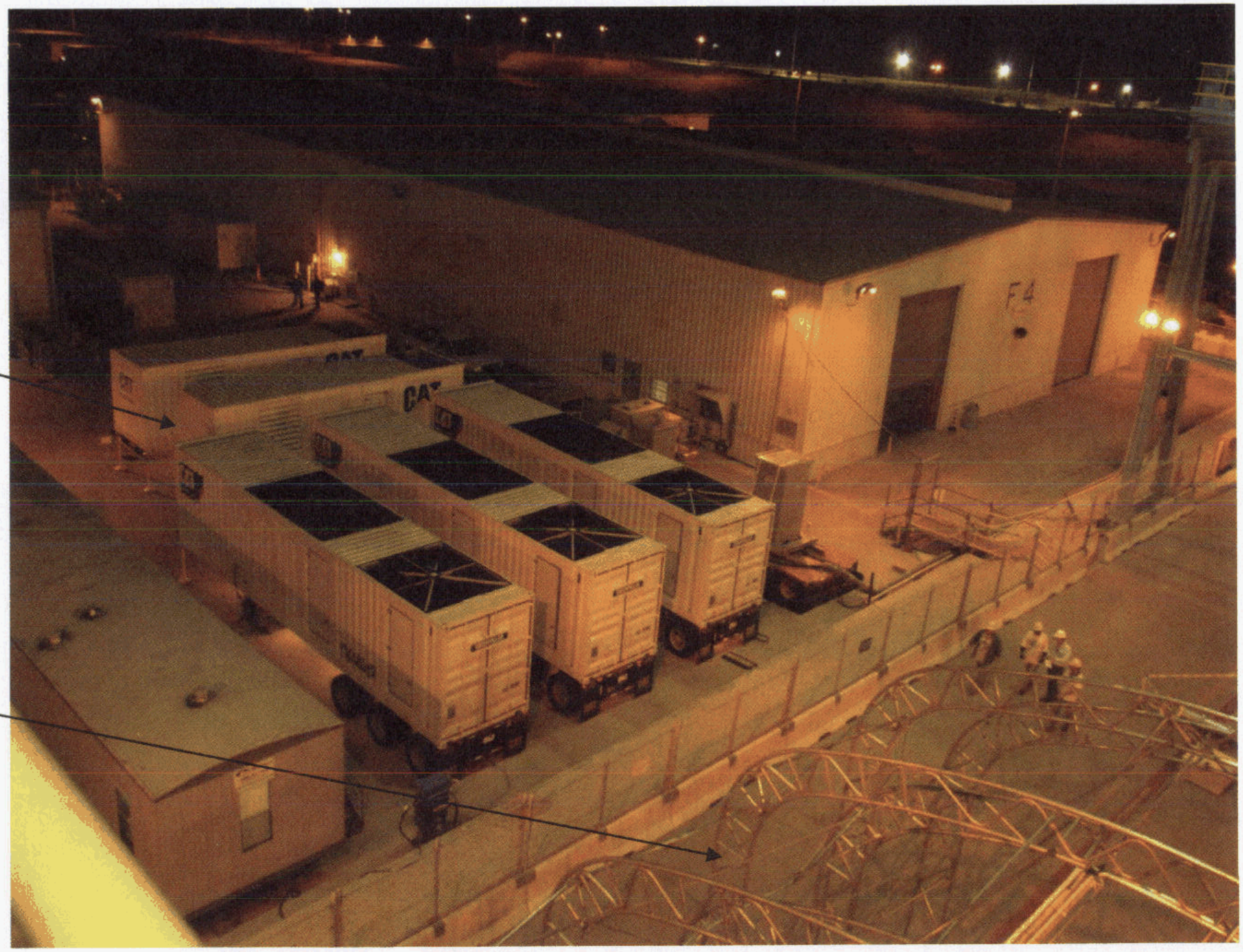
Moisture Separator Reheater

High Pressure Turbine

Docket No. 110009-EI
St. Lucie Photographs
Exhibit WBD-10,Page 3 of 4

Laydown of South Turbine Building

Temporary Diesel Generators to support Main Generator Testing



Construction of Environmental Structures to cover the Main Generator during rewind

Docket No. 110009-EI
St. Lucie Photographs
Exhibit WBD-10,Page 4 of 4

WBD-11

2010 PTN Unit 3 Outage

Modifications Planned 01/01/2010

Install NaTB Baskets for pH control (partial)	
Feedwater Heater Drains Digital Upgrades	deferred to 3R26 in June
LEFM - Spool Piece only	
Main Transformer Cooler Upgrade	
Switchyard Upgrades (partial)	
Iso Phase Bus Duct Replacement	deferred to 3R26 in March
Heater Drain Valve Replacement	
Feedwater Heater #5 Drain Piping Upgrade	
FAC Identified Piping Replacement-Phase A. Unit 3 #6 Extraction Steam (partial)	
Replace #5, #6 A/B Feedwater Heaters	
Feedwater Heater 1-4 inspections and Contingency PC/M for FWHTR Repairs	

Modifications Implemented

Install NaTB Baskets for pH control (partial)	
LEFM - Spool Piece only	
Main Transformer Cooler Upgrade	
Switchyard Upgrades (partial)	
Heater Drain Valve Replacement (partial)	scope reduced in July
Feedwater Heater #5 Drain Piping Upgrade (partial)	scope reduced in June
FAC Identified Piping Replacement-Phase A. Unit 3 #6 Extraction Steam (partial)	scope reduced in June
Replace #5, #6 A/B Feedwater Heaters (partial)	scope reduced in June
Feedwater Heater 1-4 inspections and Contingency PC/M for FWHTR Repairs	
Installation of Condenser Basket Tips	scope added in August

Docket No. 110009-EI
PTN3R25 and 4R26
EPU Outage Details
Exhibit WBD-11, Page 1 of 3

3R25 Outage Schedule

Planned Start	9/27/2010
Actual Start	9/25/2010
Planned Finish	10/30/2011
Actual Finish	11/9/2010

3R25 Outage Cost

Planned Cost	$20.9M
Actual Cost	$18.7M

Notes:

Plant trip due to Main transformer failure caused early outage start

EPU scope was completed on time, late actual finish caused by plant restart issues

Due to rescoping effort, the outage planned cost could not be obtained until 9/24/2010

Outage costs reflected only apply to costs incurred during the outage period and do not include materials

2011 PTN Unit 4 Outage - Planned Start 3/19

Modifications Planned 01/01/2011	PC/M Status	Material Status
Modify Deluge Piping at Main transformer	CRN sched 1/19	no issues
Install NaTB Baskets for pH control (partial)	issued	NaTB Baskets due on site 2/28
Feedwater Heater Drains Digital Upgrades (partial)	issued	Digital positioners due on site 3/9
LEFM - Spool Piece only	issued	no issues
Main Transformer Cooler Upgrade	issued	no issues
Switchyard Upgrades (partial)	issued	no issues
Iso Phase Bus Duct Replacement	issued	no issues
Heater Drain Valve Replacement	issued	no issues
Feedwater Heater #5 Drain Piping Upgrade (partial)	issued	no issues
Replace #5, #6 A/B Feedwater Heaters (partial)	issued	supports due on site 2/10
Feedwater Heater 1-4 inspections and Contingency PC/M for FWHTR Repairs	issued	no issues
Installation of Condenser Basket Tips	issued	no issues
Spent Fuel Pool Power Supply	sched 2/16	cable due on site 2/9
Seismic Scaffold in Control Room	sched 2/22	no issues

Docket No. 110009-EI
PTN3R25 and 4R26
EPU Outage Details
Exhibit WBD-11, Page 3 of 3

WBD-12

PSL - SL1-23 Spring 2010 Scope

Planned Modifications

Feedwater Heater / Drain Cooler Tube inspections
Feedwater Heater Nozzle inspections
Inspect FE-11-8A/B shell side drain lines
Iso Phase Bus Duct Cooling test ports
Rod Control - Phase II
T&D - St. Lucie Switch Replacement
Turbine Performance Test Points

Implemented Modificatiosn

Feedwater Heater / Drain Cooler Tube inspections
Feedwater Heater Nozzle inspections
Inspect FE-11-8A/B shell side drain lines
Iso Phase Bus Duct Cooling test ports
Rod Control
T&D - St. Lucie Switch Replacement
Turbine Performance Test Points
Add'l scope:
Feedwater Heater Nozzle Repairs (4A/B) - Required based on results of planned inspections.

PSL - SL1-23 Spring 2010 Schedule

Planned Start 04/05/10
Actual Start 04/05/10

Planned Finish 05/20/10
Actual Finish 06/14/10 (Plant extension - not EPU Related)

PSL - SL1-23 Spring 2010 Cost

Planned $18M
Actual $18.4M
Variance primarily driven by FWH Nozzle Repairs.

PSL - SL1-23 Spring 2010 Notes
EPU Completed on schedule.

PSL - SL2-20 Spring 2011 Scope

Planned Modifications

Condensate Pump Replacement
Exciter Cooler Upgrade
Feedwater Heater / Drain Cooler Tube inspections
Feedwater Heater Nozzle inspections
Generator CTs and Bushings and PSS
Generator Environmental Structure
Generator H2 Seal Oil Pressure Increase
Generator Hydrogen Coolers
Generator Loop Test Trailer
Generator Upgrade Rotor Repl & Stator Rewind
Inspect FE-11-8A/B shell side drain lines
LP Turbine Rotor
Main Transformer Replacement (Unit 2)
Rod Control Phase III
St. Lucie Metering and Relay
T&D - St. Lucie Switch Replacement
Turbine Lube Oil Lift Pump Motor Replacement (MSP)

All planned modifications are on track to complete.

PSL - SL2-20 Spring 2011 Schedule

Planned Start 01/03/11
Actual Start 01/03/11

Planned Finish 03/09/11
Actual Finish

PSL - SL2-20 Spring 2010 Cost

Planned $75.5M
Actual

PSL - SL2-20 Spring 2010 Notes

PSL - SL1-24 Fall 2011 Scope

Planned Modifications	EC Status	Material Status
Condenser Mods/Air Removal	02/03/11	No Current issues
Containment Mini Purge	04/29/11	No Current issues
CS Pump Flow Impacts	09/06/11	No Current issues
DCS Mods for LEFM and FW Ctrls	03/09/11	No Current issues
DEH Computer Replacement	06/16/11	No Current issues
Electrical Bus Margin Improvement	02/16/11	No Current issues
EPU Piping Vibration Modifications	03/22/11	No Current issues
Exciter Cooler / Blower Upgrade	Complete	No Current issues
Feedwater Vent Orifice Re-size	03/16/11	No Current issues
Generator Core Replacement	03/28/11	No Current issues
Generator CT & Bushings	03/30/11	No Current issues
Generator Environmental Structure	04/06/11	No Current issues
Generator H2 Coolers	01/21/11	No Current issues
Generator H2 Seal Oil Pressure Increase	01/26/11	No Current issues
Generator Rotor Replacement & Stator Rewind	03/28/11	No Current issues
Heater Digital Controls	02/23/11	No Current issues
Hot Leg Injection Improve Flow	04/01/11	No Current issues
HP Turbine Rotor	03/02/11	No Current issues
ISO Phase Bus Duct Cooling	03/28/11	No Current issues
Isophase Bus Supports	06/13/11	No Current issues
LEFM Leading Edge Flow Meter	03/16/11	No Current issues
Loop Test Trailer	01/24/11	No Current issues
LP Turbine Rotor	01/21/11	No Current issues
Main Transformer Cooler Upgrade	03/18/10	No Current issues
MS Condensate & FW Piping Supports	06/17/11	No Current issues
MSIV Actuator Replacement	07/20/11	No Current issues
MSR Replacement	04/20/11	No Current issues
MSR/Heater Drain Valves Upgrade	03/08/11	No Current issues
Refurbish Feedwater Reg Valve	01/26/11	No Current issues
Replace Feedwater Heater 5A/B	04/28/11	No Current issues
Replace FW Pump and Spare	04/06/11	No Current issues - On Tei watch list
Replace Heater Drain Pump	02/10/11	No Current issues - On Tei watch list
Rod Control	N/A	No Current issues
Safety Injection Tank Requal	05/04/11	No Current issues
Setpoints & Scaling BOP	Complete	No Current issues
Setpoints & Scaling NSSS	Complete	No Current issues
St. Lucie Metering and Relay	04/12/11	No Current issues
Steam Bypass Controls System (DCS)	Complete	No Current issues
Steam Bypass Flow to Condenser - Increase	04/13/11	No Current issues
TCW Heat Exchanger Replacement	01/21/11	No Current issues
Umbrella Mod	08/09/11	No Current issues