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DOCKET NO.: 960409-EI (TAMPA ELECTRIC COMPANY)

WITNESS: ROBERT D. NIEKUM AND ERIC G. MAJOR

DESCRIPTION: PANEL DEPOSITIONS OF ROBERT D. NIEKUM AND
ERIC G. MAJOR PLUS EXHIBITS SUBMITTED FOR
FILING BY THE STAFF OF THE FLORIDA PUBLIC
SERVICE COMMISSION

DATE FILED: JUNE 14, 1996

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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

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In The Matter of :
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Prudence review to : DOCKET NO.: 960409-EI
determine regulatory :
treatment of Tampa : FILED: May 30, 1996
Electric Company's Polk :
Unit. :
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VOLUME I, PAGES 1 - 114

PANEL
DEPOSITION OF: ROBERT D. NIEKUM
and
ERIC G. MAJOR

TAKEN BY: The Staff of the Florida
Public Service Commission

PLACE: Florida Power Corporation
Building A
9th Floor Conference Room
3201 34th Street South
St. Petersburg, Florida

TIME: Commenced at 9:05 a.m.
Concluded at 4:01 p.m.

DATE: Tuesday, June 4, 1994

REPORTED BY: Donna W. Everhart
CSR, RPR, CP, CM
Certified Shorthand
Reporter
Notary Public
State of Florida at Large

BUREAU OF REPORTING
RECEIVED 6-12-96

ORIGINAL

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11 ALSO PRESENT:

12 THOMAS L. HERNANDEZ, Director, Resource
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14 GREGORY M. NELSON, Senior Engineer,
Environmental Compliance Coordinator, Corporate
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15 MARY JO PENNINO, Manager, Energy Issues
and Administration, Regulatory Affairs, Tampa
Electric Company.

16 KARL WIELAND, Florida Power Corporation.

17 KENNETH DUDLEY, (By Telephone) Florida
Public Service Commission Staff.

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IT IS STIPULATED that this panel deposition was taken pursuant to notice in accordance with the applicable Florida Rules of Civil Procedure; that objections, except as to the form of the question, are reserved until hearing in this cause; and that reading and signing was not waived.

1 THEREUPON,

2 ROBERT D. NIEKUM and ERIC G. MAJOR
3 appeared as witnesses and, after being duly sworn
4 by the court reporter, testified as follows:

5 EXAMINATION

6 BY MR. ELIAS:

7 Q. Good morning. My name is Robert Elias.
8 I am staff attorney with the Florida Public Service
9 Commission. We are here pursuant to a notice for
10 the depositions of Robert Niekum and Eric Major in
11 Docket No. 960409-EI.

12 By agreement of all parties present at
13 this deposition, the deposition will be conducted
14 as a panel in the hopes of eliciting the
15 information sought in the most expedient time
16 frame. For the sake of expediency, if I believe a
17 particular question should be directed to one of
18 the individuals, I will name you specifically, and
19 if you can't answer, then defer to the other
20 individual.

21 I would expect that the bulk of my
22 questions certainly at the initial phases of the
23 deposition will be most appropriately answered by
24 Mr. Niekum, and then as we go along, probably to
25 Mr. Major, but as you see appropriate, please, with

1 due regard for the court reporter's concerns, do
2 please don't hesitate to answer.

3 I'd ask that both witnesses state their
4 names for the record.

5 A. (Mr. Niekum) My name is Robert D.
6 Niekum. My business address is 3201 34th Street
7 South, St. Petersburg, Florida 33711.

8 A. (Mr. Major) My name is Eric G. Major. My
9 business address is 3201 34th Street South,
10 St. Petersburg, Florida 33711.

11 Q. And Mr. Niekum, by whom are you employed?

12 A. (Mr. Niekum) By Florida Power
13 Corporation.

14 Q. And what is your current position?

15 A. (Mr. Niekum) My current position is
16 director of fuel supply.

17 Q. And how long have you been employed by
18 Florida Power Corporation?

19 A. (Mr. Niekum) Just a little over 14 years.

20 Q. And prior to that, what was the general
21 nature of your work experience?

22 A. (Mr. Niekum) Prior to that, I attended
23 the University of Florida in the graduate program,
24 and prior to that I worked for the Jacksonville
25 Electric Authority in various engineering

1 positions.

2 Q. Would you describe your job duties
3 sequentially since you came to work for Florida
4 Power Corporation.

5 A. (Mr. Niekum) I was initially hired into
6 Florida Power Corporation as a transmission
7 distribution planning engineer. In about 1983 I
8 was promoted to senior transmission and
9 distribution planning engineer. In 1989 I was
10 moved to the position of senior generation planning
11 engineer. And in 1990 I was promoted to manager of
12 generation planning. Then in March of 1995, I was
13 promoted to director of fuel supply.

14 Q. Would you describe your job
15 responsibilities as a senior generation planner.
16 That was your position?

17 A. (Mr. Niekum) Yes. As a senior generation
18 planner, I was responsible for doing detailed
19 generation expansion studies and economic analysis
20 of various generation alternatives. That included
21 risk analysis of various alternatives and some
22 computer programming.

23 Q. What specific generation expansion plans
24 did you perform detailed analysis for in the 1989
25 to 1990 time frame?

1 A. (Mr. Niekum) There was a requirement, I
2 believe, by the Public Service Commission for a
3 filing in about October of 1990 to look at avoided
4 units for cogeneration. We were required to do a
5 generation facility plan at that time, and so I was
6 involved in the decision making of producing those
7 studies. If I understand your question, what
8 alternatives did we look at, we had a substantial
9 list of different technologies that were considered
10 plausible at that time, so it would have included a
11 wide variety of generation technologies and also
12 various DSM programs.

13 Q. And did there come a time when one of
14 these expansion plans was chosen by Florida Power
15 Corporation for its next unit to be constructed?

16 A. (Mr. Niekum) Yes. We did a study in 1991
17 that resulted in us applying to the Commission for
18 need certification for the Polk County gas-fired
19 combined cycle units that went to hearing in late
20 1991.

21 Q. Would you describe in as much detail as
22 you can remember that study and what the
23 alternatives were and what your conclusions were.

24 A. (Mr. Niekum) The study involved looking
25 at what we considered to be viable generation

1 technologies at the time. We tried to make sure
2 that we set criteria that the generation
3 alternatives that we selected were actually
4 commercially viable and could be built because we
5 felt that we were doing a study that would result
6 in the construction of a plant.

7 Q. As specifically as you can remember, what
8 particular technologies did you evaluate?

9 A. (Mr. Niekum) We evaluated
10 distillate-fired combustion turbines,
11 natural-gas-fired combustion turbines,
12 natural-gas-fired combined cycle units,
13 distillate-fired combined cycle units, I believe
14 small and large pulverized coal plants. We looked
15 at coal gasification, integrated coal gasification
16 plants. We looked at integrated gasification of
17 orimulsion. There were one or two others that I
18 would have to go back to reference to see that were
19 in there as well. I believe we looked at a
20 purchased power agreement with OUC in conjunction
21 with the gas-fired combined cycle unit was one of
22 our options.

23 Q. Of the alternatives that you evaluated,
24 which one did Florida Power Corporation select for
25 its next generating unit?

1 A. (Mr. Niekum) We selected the gas-fired
2 combined cycle unit.

3 Q. And why was that?

4 A. (Mr. Niekum) We went through a rather
5 detailed analysis of the present worth revenue
6 requirements required over the life of that plan to
7 see which selection would be the best long-term
8 alternative. We also conducted a rather extensive
9 risk analysis looking at variations in our forecast
10 assumptions, looking at variations in the load
11 forecast, fuel forecast, and the financing costs of
12 different -- to select financing for the unit. And
13 we looked at all the combinations of those
14 variations and did a detailed risk analysis to see
15 what the -- which technology had the highest
16 likelihood of being successful, and that was the
17 genesis of getting the result that the gas-fired
18 combined cycle unit was the best overall.

19 Q. And as compared to the alternatives, was
20 combined cycle just the best or was it clearly
21 better than any of the alternatives? In other
22 words, after performing this analysis, how close
23 were the competing alternatives?

24 A. (Mr. Niekum) I have the reference here
25 that shows that. It's hard to recall precisely

1 from memory, but would you like me to give copies
2 of this?

3 Q. If you have --

4 A. (Mr. Niekum) I have a number of them.

5 Q. Okay. Let's do this. You were asked to
6 produce a number of documents in the subpoena. Do
7 you have them with you?

8 A. (Mr. Niekum) We have some of them.
9 Because of the short time frame, some of them we
10 don't have all the documents, but I believe we have
11 some of the key ones. One is the integrated
12 resource study, which has some of the detail of at
13 least this initial line of questions.

14 Q. All right. If you have copies to pass
15 out, that would be great. If we could mark it as
16 Exhibit A to the transcript.

17 (Deposition Exhibit No. A identified.)

18 A. (Mr. Niekum) I guess to answer your
19 question on how the judgment was made of which
20 was -- which alternative was the best and why, by
21 way of explanation, I probably should start on
22 about page 135 of the document I just handed out,
23 which is the economic and risk analysis, which was
24 key to our decision making.

25 And if you look on page 138, that

1 decision tree with probability table indicates the
2 method that we used to generate a wide variety of
3 scenarios with different forecasting. In other
4 words, there were 27 combinations of high, medium
5 or low fuel forecast, high, medium or low demand
6 and energy forecast, and high, medium and low cost
7 of technology, capital cost of technology
8 uncertainty.

9 We then did a long-term revenue analysis
10 on each of these -- each of these scenarios for
11 each of the 10 alternatives we selected, so -- for
12 looking out over 30 years. So it was a rather
13 extensive analysis of the revenue requirements for
14 every combination of future forecast with every
15 technology. So it was a substantial number of
16 analyses.

17 BY MR. ELIAS:

18 Q. So if I understand it right, you
19 basically evaluated 270 different scenarios, 10
20 generating alternatives times 27 different
21 combinations of fuel uncertainty, demand and energy
22 uncertainty, and capital cost of technology
23 uncertainty?

24 A. (Mr. Niekum) Yes. Then on page 140 and
25 141, the revenue requirement is weighted by the

1 probability of the occurrence of that combination
2 of forecasts. We did an expected value of the
3 revenue requirements and plotted the results, the
4 differences in the results of all 10 alternatives
5 to see which of the alternatives looked like the
6 best.

7 Q. Okay. You're speaking of Figures 8.2 and
8 8.3 located on page 140 and 141 of the integrated
9 resource study?

10 A. (Mr. Niekum) Yes.

11 Q. Could you step me through those two
12 tables?

13 A. (Mr. Niekum) Yes. What these numbers
14 don't -- these numbers represent the difference in
15 revenue requirements compared to any one of the
16 base cases. In this case, we said the base is our
17 combined cycle on gas option, which is -- so the
18 difference between its revenue requirements in
19 itself is zero. And so that's why it's a baseline
20 says zero. It says that if you take its total
21 revenue requirements and subtract its revenue
22 requirements from itself, the difference, of
23 course, is zero.

24 And then what you do is look at the
25 revenue requirements of all the other alternatives

1 and subtract them and then plot the differences.
2 If the line goes below the zero line, it says that
3 alternative is cheaper in that year on a cumulative
4 revenue requirements basis. If the line is above
5 the zero line, it says that alternative is more
6 expensive than our selected option.

7 So what this graph shows is that two of
8 the options for a number of years were slightly
9 less expensive than the gas-fired combined cycle.
10 That would be the small combustion turbine, which
11 was Option No. 5, and the UPS agreement, which was
12 a purchase from Cajun Electric that we were looking
13 at for a number of years, in a short time frame was
14 also slightly less expensive but over the long term
15 it was more expensive. Every other option was more
16 expensive.

17 Now what we've done is we grouped the
18 most likely challengers on Figure 8.2, so these
19 were the most likely contenders, and then Figure
20 8.3 indicates the alternatives that were
21 considerably more expensive. If you look at the
22 scale, you can see that in Figure 8.2, the scale
23 goes from minus 20,000 to 140,000; whereas, on the
24 scale on the other side it's minus 100,000 to over
25 800,000. So it says that the groups in 8.3 were

1 less competitive.

2 Q. The difference in cumulative present
3 worth revenue requirements is in thousands of
4 dollars?

5 A. (Mr. Niekum) It's actually in -- it's in
6 thousands but, for instance, on 8.2, the scale
7 would be the top number would be \$140 million
8 total. So that was one analysis. That was one
9 method of comparing the alternatives and making a
10 selection.

11 We also extended this analysis, and these
12 next set of curves are a bit more complicated, but
13 they begin on page 145 and 146. And these
14 represent a risk profile that shows what the
15 likelihood of one of the alternatives being better
16 than our selection.

17 If we said that our selection is the
18 gas-fired combined cycle, these tables, it takes a
19 bit of explanation to try and go through them, but
20 what they demonstrate and the way you can read them
21 is to estimate the probability that one selection
22 would be better than ours, because there is a
23 collection of future forecasts that could occur
24 that could make one of the other alternatives
25 better than the one we selected.

1 Q. Specifically to the best that you can
2 recall, what variables would have made one of the
3 alternatives more effective than the base case
4 choice?

5 A. (Mr. Niekum) Generally the coal options
6 would have looked better if the fuel forecasts were
7 high and the cost of capital was low and the demand
8 and energy forecast was high. You would generally
9 have a requirement to generate more energy, the
10 alternative of gas and oil would be more expensive
11 to produce that energy, and the cost to construct
12 the facility would be less because your cost of
13 capital would be less.

14 So in instances where those circumstances
15 would occur, you would see the coal options or the
16 orimulsion option be superior. In cases where the
17 fuel forecast was lower and the cost of capital
18 went up, then you'd see the gas-fired and oil-fired
19 alternatives look better.

20 Q. Of the three particular variables that
21 you described, looking back with 20/20 hindsight
22 over the six-year period, what has or has not come
23 to pass?

24 A. (Mr. Niekum) In general, we have seen
25 lower fuel prices than we projected.

1 Q. Which would tend to support the combined
2 cycle or the natural-gas-fired alternatives?

3 A. (Mr. Niekum) In general, yes. Not in and
4 of itself would be the deciding factor, but, yes,
5 it would favor those because of lower fuel prices.

6 Q. And as far as the capital and the demand
7 and energy, capital cost and demand and energy, how
8 have those fared versus what you were --

9 A. (Mr. Niekum) I believe capital costs have
10 also gone down from some of the rates that we
11 thought we would see, probably have gone down some,
12 which were not particularly in favor of the
13 gas-fired combined cycle. The demand and energy
14 forecast I think is a bit lower than what we had
15 forecast back then, but not substantially, but it
16 is lower.

17 If I might just comment on how you read
18 these graphs on 8.4 and 8.5, one way to look at it
19 is when you see one of the lines cross the zero
20 line, at the point where it crosses; for instance,
21 where it says -- I will use the example of UPS No.
22 10, which was an option where we were looking at
23 buying some power from Cajun Electric in Louisiana,
24 if you see that line that starts at zero and at
25 minus 200,000 and eventually extends up and crosses

1 the line at approximately 0.4, the way you would
2 read that is it would say that the UPS agreement
3 had about a 40 percent probability of being a less
4 expensive option than the one we selected. That's
5 the way you would interpret these graphs.

6 So certain options like the one closer to
7 the top, the small combustion turbine, No. 5,
8 crosses at a roughly about 20, 25 percent. It's
9 the heavy black dash line that crosses at about 25
10 percent. It said it had about a 25 percent
11 probability of beating our selected option.

12 So any time you make a choice like this,
13 there is always the uncertainty that circumstances
14 can change and your option may or may not be
15 successful, but this is some way to try and
16 quantify what that risk is.

17 Q. Is there any way to tell -- or let me ask
18 you something about this study. Are the cumulative
19 present worth revenue requirements and the
20 significant assumptions for each of these
21 alternatives listed anywhere in this study?

22 A. (Mr. Niekum) If I understand the
23 question, the risk assumptions are described in
24 terms of fuel forecast uncertainty, and in the
25 appendix we have the high, medium and low fuel

1 forecast and some of the numbers that we used in
2 the study. Maybe I'm not clear on exactly what
3 you're asking.

4 Q. In other words, say for example, taking a
5 look at Figure 8.5.

6 A. (Mr. Niekum) Okay.

7 Q. And just picking say the pulverized coal
8 (700), does that 700 stand for 700 megawatts?

9 A. (Mr. Niekum) Yes. These are kind of
10 brief descriptions of the alternatives. In the
11 appendix is a description of each option, a
12 generalized description of each option, and that
13 begins on page 306. And it tries to give a
14 one-page summary of the description of how the
15 alternative was modeled and what kind of basic
16 assumptions were used.

17 Q. My question was: Is there anywhere in
18 this study where the total revenue requirements
19 associated with this option using all of the
20 assumptions that are embodied in this comparative
21 analysis and this comparative cumulative present
22 worth revenue requirements is listed?

23 A. (Mr. Niekum) I'm not sure that it's in
24 this document. I think since this was a part of a
25 large number of documents submitted in the hearing,

1 I would have to go back and check. I don't think
2 that it's in here. But I'm not -- I'm not entirely
3 sure that it may not be somewhere, but I don't
4 think so. I don't think it's in this document.

5 Q. Let me direct you to page 143.

6 A. (Mr. Niekum) Okay.

7 Q. On that page listed is a series of
8 discount rates, AFUDC rates, capitalization rates,
9 projected cost of capitals. Do these represent the
10 economic assumptions that were used for all of the
11 alternatives?

12 A. (Mr. Niekum) Yes.

13 Q. So they were held constant?

14 A. (Mr. Niekum) Yes. With the variations in
15 things like book life of combustion turbines and
16 IGCC and combined cycle are a little different,
17 but, yes, these were the assumptions.

18 Q. Now, were each of the alternatives
19 modeled based on FPC's existing system and the
20 projections about variable costs; in other words,
21 was the dispatch order of each of these
22 alternatives considered in the calculation of the
23 cumulative present worth revenue requirements?

24 A. (Mr. Niekum) Yes. These were -- these
25 were modeled through the -- through PROSCREEN,

1 which is a model that has an economic dispatch
2 model and an economic financial model as well, and
3 so the calculation of the revenue requirements
4 includes both a fuel cost and the capital cost and
5 any other expenses O & M costs included.

6 Q. Would it reflect the fuel cost as that
7 unit would dispatch on FPC's system?

8 A. (Mr. Niekum) Yes.

9 Q. Based on your assumptions about fuel and
10 variable O & M?

11 A. (Mr. Niekum) Yes.

12 Q. So you came up with combined cycle gas as
13 the most appropriate choice for Florida Power
14 Corporation's next unit. What did you do then?

15 A. (Mr. Niekum) This was submitted in August
16 of 1991 as part of our filing and for the
17 construction of the Polk County project, I guess.
18 We then filed or went to hearing in November of
19 1991, and the Commission came back with an order
20 approving 470 megawatts at Polk County and the
21 construction of two units, one in 1998 and one in
22 1999.

23 Q. How did the Commission's decision or how
24 would the Commission's decision to approve two
25 rather than four units proposed affect this

1 analysis?

2 A. (Mr. Niekum) It really didn't have that
3 much effect because the technology choice at least
4 on our system was relatively clear. The real
5 question became an issue of one of how much demand
6 and energy forecast would grow, whether we would
7 need additional units beyond the first two and how
8 certain were we of our demand and energy forecast
9 going out at that time about 13 years. And so it
10 was really a question of just how many, not really
11 what we were building.

12 Q. After the Commission determined the need
13 for 470 megawatts of capacity, what did Florida
14 Power Corp. do next?

15 A. (Mr. Niekum) Well, after we began, we had
16 our order, we then began the site certification
17 process of getting the site licensed to do that
18 construction.

19 Q. What particular site did Florida Power
20 Corporation choose?

21 A. (Mr. Niekum) I may defer that to Eric
22 Major. He might be able to give a little more
23 detail on exactly how we picked the site and how it
24 was selected.

25 A. (Mr. Major) We chose the Polk County site

1 just outside of Fort Meade, and that was presented
2 in the need hearings for the combined cycle units.

3 Q. How did you come to choose that site?
4 Were you involved in that selection?

5 A. (Mr. Major) I was involved at the very
6 tail end of that selection, but --

7 Q. And what time frame would that have been?

8 A. (Mr. Major) That the site selection
9 concluded in, I believe, late '89.

10 Q. And did Florida Power Corporation use a
11 citizen group or any other -- how was the site
12 selected?

13 A. (Mr. Major) We had a team of internal
14 participants representing the planning area, public
15 affairs, environmental, construction, engineering,
16 and then we also formed an environmental advisory
17 group. I'm not positive on the numbers of
18 participants, but they assisted us in going through
19 the site selection process, which took about two
20 years, close to two years.

21 Q. To the extent that you know, what were
22 the reasons why the Polk County site was favored
23 over some of the alternatives that you considered?

24 A. (Mr. Major) I think the primary reasons
25 were environmental in terms of having the lesser of

1 the environmental impacts, and also on a cost
2 basis. I think all things considered, life cycle
3 cost considering fuel deliveries, fuel choice, the
4 economics favored the Polk County site as well.

5 Q. And were those -- were the costs for
6 developing the Polk County site included in this
7 analysis?

8 A. (Mr. Major) Bob would have to answer that
9 one.

10 A. (Mr. Niekum) The cost of the site
11 development was not included in this analysis, and
12 the reason being it was held to be a common cost,
13 so that amongst the selection of alternatives, it
14 was considered, at least in our thinking at that
15 time, as a constant that would have not made a
16 significant change in the results.

17 Q. Was information concerning the Polk site
18 presented to the Commission in the need
19 determination hearing?

20 A. (Mr. Major) Yes.

21 Q. Mr. Niekum, what do you remember about
22 that, if anything?

23 A. (Mr. Niekum) Yes, there was -- there were
24 several issues at that -- at the hearing regarding
25 the development of the site, the fact it was coal

1 capable, and the fact that environmentally we at
2 least had tracked down a site that was acceptable
3 to the advisory group. I don't think -- I don't
4 really remember if the Commission approved or
5 disapproved of what we were doing, but it was
6 brought to their attention that this would be the
7 location of the project we were proposing.

8 Q. Okay. You mentioned that you filed a
9 certification application with the Department of
10 Environmental Regulation. What other activities
11 were undertaken in that time frame in connection
12 with the construction of the plant?

13 A. (Mr. Major) Let me answer that. I think
14 the primary activities following receipt of the
15 need determination involved the site certification,
16 preparing the studies concerning air impacts, water
17 consumption, land use, all the factors that are
18 looked at during site certification. And that
19 activity went on from early '92 through the receipt
20 of the Department of Environmental Protection's
21 certification and governor and Cabinet approval in,
22 I believe, January of '94.

23 Q. Were any limitations or other
24 contingencies placed on the certifications, on the
25 certification versus what you had requested or

1 sought?

2 A. (Mr. Major) No. When we -- when we went
3 for site certification, the specific approval was
4 secured to build the 470 megawatts, but we also
5 secured approval for the ultimate development of
6 the site and demonstrated the ultimate capability
7 of the site as 3,000 megawatts with a combination
8 of natural gas combined cycle units and coal
9 gasification units at a later date.

10 Q. In between the time that the Commission
11 granted the determination of need and certification
12 was received from -- a site certification was
13 received from the governor and Cabinet, did Florida
14 Power Corporation perform any cost effectiveness
15 studies or evaluations of the cost effectiveness of
16 its next planned addition, unit addition?

17 A. (Mr. Niekum) We conducted an integrated
18 resource plan in -- I believe starting in 1993 as
19 part of the DSM goals proceeding, and there was a
20 requirement at that time to do integrated resource
21 planning, and its primary focus was to look at
22 units to be avoided by DSM programs. So we did go
23 through a rather elaborate process of going through
24 integrated resource planning, but during those
25 planning phases, we worked under the assumption

1 that we were not revisiting Polk but we were
2 looking at the possibility of what other
3 alternatives we would have as our next units to be
4 put on our system.

5 Q. Was there anything about that evaluation
6 that suggested that maybe a resource addition was
7 not the most appropriate or no longer appropriate?

8 A. (Mr. Niekum) No. In general what we
9 found was that our next unit tended to be very
10 similar technology, that we saw that the repowering
11 of our Higgins and Turner plants, which basically
12 were gas-fired combined cycle units during the
13 repowering were the next best alternative, and we
14 didn't see that there was any significant change in
15 our overall philosophy of what the next units on
16 our system would be that would cause you to revisit
17 Polk.

18 Q. At any time since the determination of
19 need was granted by the Commission in 1992, did
20 Florida Power Corporation perform an in-depth
21 analysis of the cost effectiveness of its planned
22 unit addition?

23 A. (Mr. Major) Let me answer that.
24 Immediately following the receipt of the site
25 certification, which we got in January of '94,

1 realizing that we would be making significant
2 expenditures beyond that point, we addressed the
3 Polk County issue in terms of looking at what, in
4 our opinion, would be the most competitive
5 alternatives to going forward with the first two
6 units at Polk.

7 And we did an analysis that I guess
8 concluded in a draft report in February of '94.
9 And there we compared the Polk County additions
10 with repowering options at Higgins and Turner,
11 evaluating doing those first ahead of the Polk
12 County unit, and we also evaluated not going
13 forward with the total site development at Polk
14 County for the large site but considered a -- we
15 called it a postage stamp site, going with a
16 smaller site and constructing combined cycle units
17 on postage stamp sites after the repowering
18 projects at Higgins and Turner.

19 And the results indicated that longer
20 term, okay, when you factor in additions, I think,
21 through the year 2004 and the life cycle costs of
22 those units, that the planned development in Polk
23 County that we had received approval from the
24 Commission on was the least-cost alternative.

25 Q. When you say -- just to clarify, when you

1 say "life cycle costs," would you explain what
2 costs you include and how you define that term?

3 A. (Mr. Major) In terms of life cycle cost,
4 it's the initial capital cost of the plant and the
5 plant operating and maintenance costs, fuel, over
6 the expected life of the unit. It's similar to a
7 present worth revenue requirement that Bob had
8 mentioned in his earlier.

9 Q. Does that include the fuel costs and
10 variable operating and maintenance expense based on
11 the expected dispatch on Florida Power Corp.'s
12 system?

13 A. (Mr. Major) That is correct.

14 Q. So then each alternative would be modeled
15 based on the way it would operate on Florida Power
16 Corporation's system?

17 A. (Mr. Major) That is correct.

18 Q. And different units could have different
19 capacity factors based on the variable operating
20 costs and the impact on economic dispatch on your
21 system?

22 A. (Mr. Major) Yes.

23 Q. You mentioned a draft report. Was that
24 reduced to writing?

25 A. (Mr. Major) Yes, it was.

1 Q. Do you have it?

2 A. (Mr. Major) I've got it here, yes.

3 MR. ELIAS: Do you have copies of this?

4 MR. MCGEE: Unlike the other one, we
5 don't have copies made of this one.

6 MR. ELIAS: If I may just look through
7 this.

8 BY MR. ELIAS:

9 Q. Were you one of the authors of this plan?

10 A. (Mr. Major) Yeah. I authored pieces of
11 that, yes.

12 Q. Okay. Would you step me through the
13 parts that you authored.

14 A. (Mr. Major) It was the front part that
15 gave a history -- well, gave a current status of
16 where we were with the project, gave a history and
17 talked through some of the economics and the
18 evaluations that had been done.

19 Q. Now, it speaks here to monies already
20 committed on the Polk project amount to
21 \$30 million. What were those monies expended for
22 at that time?

23 A. (Mr. Major) Those monies included the
24 site selection process, which totaled approximately
25 \$1.7 million, and the monies expended in going

1 through the need determination before the Public
2 Service Commission and the monies involved in
3 securing the site certification of the plant, and I
4 believe there were some option monies on properties
5 that were being purchased.

6 Q. What factors that you considered in this
7 evaluation tended to or would have tended to work
8 against the cost effectiveness of the Polk planned
9 addition? In other words, from the time of the
10 need determination to the time of this study, what
11 changes took place that would have made this choice
12 less cost effective?

13 A. (Mr. Major) At the time that evaluation
14 was done, I don't believe that there were any
15 significant changes that we had identified from the
16 original need determination. If anything, the site
17 costs, okay, developing the site that would have
18 ultimate capacity capability of 3,000 megawatts,
19 that was an initial expense that detracted from the
20 potential economics of the initial unit that would
21 go at Polk County, but when you looked at
22 succeeding generation additions, okay, over the
23 life of the site, then again on a life cycle basis
24 it always demonstrated that that was the right
25 decision to go forward with.

1 Q. Now, asking the same or different
2 question, same lines, what factors changed between
3 the time of the need determination in February of
4 1992 and the time you did this study that tended to
5 improve the cost effectiveness of the planned unit
6 addition?

7 A. (Mr. Major) I believe that our fuel
8 prices had decreased, our fuel forecasts for
9 natural gas had decreased between the time that the
10 need hearings were conducted and the time this
11 evaluation was done. That specifically did not
12 have a big bearing in that evaluation because all
13 the alternatives that we were evaluating against
14 Polk County were natural gas combined cycle units,
15 but it did improve upon the overall economics of
16 the plan.

17 Q. Why, when you did this evaluation, didn't
18 you use the same alternatives as you used in the
19 need determination?

20 A. (Mr. Major) Because I believe at a very
21 high-level overview they were not deemed to be
22 competitive with the type of generation options.

23 Q. When you say "high-level overview," do
24 you mean just based on rough back-of-the-hand
25 calculations there was no way that they were going

1 to compete or that a decision was made that these
2 just are not going to be considered?

3 A. (Mr. Major) I think it was just in
4 general discussions with our planning folks at the
5 time saying which would be the strongest competitors
6 which should we evaluate, and then that was around
7 the time that the integrated resource plan was
8 being developed. And, Bob, you can comment on that
9 in terms of which were the strongest contenders at
10 that time.

11 A. (Mr. Niekum) Yes. I think when we were
12 looking at the competitive position of Polk, we
13 were looking at what was the most likely technology
14 to be selected by independent power producers or
15 any competitor, and in general we saw that that
16 was very similar to the technology that we were
17 using and that to be looking at some other options
18 when we were this far along didn't -- I mean, it
19 could have been done, but it may have been an
20 exercise that would give you a result you pretty
21 well expected.

22 So we didn't -- I don't think we really
23 looked at going back and revisiting some of the
24 other technologies. I just don't think that we saw
25 that there was a likelihood that that would be a

1 competitive option.

2 Q. Based on analysis of known costs?

3 A. (Mr. Niekum) Well, we had lower fuel
4 forecasts. Some of the issues that had changed
5 were with coming of deregulation would be the issue
6 of would we want to make obligations that maybe
7 were more long-term that we went during the
8 uncertainty of how the markets may change.

9 We felt smaller units built either on a
10 large site or on, again, evaluating the postage
11 stamp site and relocating them or possibly even
12 some kind of distributed generation tended to be,
13 in our minds, the competitive target that we were
14 after. And so we didn't want to complicate the
15 analysis any more by adding options that in general
16 didn't look like they would be something we would
17 pursue.

18 Q. When you say competitive changes in the
19 industry, could you expand on what you mean?

20 A. (Mr. Niekum) Well, with the likelihood
21 that we would have to be price competitive with
22 independent power producers, possibly cogenerators,
23 or marketers, we wanted to at least have in our
24 minds a reasonable assurance that we were building
25 a project that could compete in that type of market

1 if we were adding new capacity. And so one of the
2 reasons for reevaluating Polk was to see that it
3 was able to -- it had a reasonable chance to
4 succeed in that type of marketplace.

5 Q. What caused Florida Power Corporation to
6 believe that the market for power generation was
7 likely to be competitive in the future or over the
8 relevant time frame?

9 A. (Mr. Niekum) Well, certainly the actions
10 at FERC on open transmission access. We've had
11 some competition in the wholesale market. There
12 have always been project developers that have been
13 looking for projects. It's just these things were
14 going on. While we don't always know the
15 specifics, we know that people are constantly
16 looking at these projects.

17 And there have been cities that have
18 looked at municipalization. Some of them have
19 changed their wholesale contracts. So we know to a
20 certain degree on the wholesale level there is
21 competition, and it may expand in the future based
22 on the actions FERC is taking in open-access
23 transmission.

24 Q. Back to this Polk County site draft
25 report, was any estimate of the revenue

1 requirements or for the approved unit included in
2 this report?

3 A. (Mr. Major) I believe that we looked
4 primarily at capital cost and -- well, let's see.
5 Can I refer to that?

6 Q. Certainly.

7 A. (Mr. Major) I'm not sure whether you
8 want -- I'll let Bob address those. We did look at
9 the revenue requirements for three different
10 options. And I had mentioned the one was building
11 the Polk County units as approved by the
12 Commission, and then following up with Higgins
13 repowering in 2001, Turner -- for 249 megawatts.
14 Turner repowering in 2002 at 498 megawatts.
15 Higgins repowering in 2004 for 124 megawatts. And
16 then Units 3 and 4 at Polk. That was pretty much
17 the plan going forward with the Polk units as we
18 had our need determination.

19 Second option was taking a look at a
20 smaller site size for Polk County; in other words,
21 not continuing with the full development of the
22 large site, and putting the initial units on a
23 smaller parcel and doing Higgins repowering as in
24 the previous plan, Turner as in the previous plan,
25 and then Units 3 and 4 at Polk on a postage, also

1 on a smaller site.

2 And then the third option was going
3 forward with the repowering ahead of the Polk
4 County units, and that had Higgins repowering in
5 1999, Turner in the year 2000, doing combined cycle
6 units in 2001 and 2002 at an undefined location,
7 coming back in 2004 doing Higgins repowering, and
8 then combined cycle units in 2004 and 2005.

9 And then I did a comparison of the
10 revenue requirements, and there again, we showed
11 the baseline was continuing forward with the site
12 at Polk County as approved by the Commission. And
13 the other options showed some earlier savings in
14 the initial years of the project, but always showed
15 that in the latter years the revenue requirements
16 would be more significant.

17 Q. What causes the revenue requirements of
18 the two alternative plans to increase in the later
19 years versus the base case plan?

20 A. (Mr. Niekum) In general, what you would
21 see is lower capital cost projects generally will
22 show the savings early on because you don't have
23 the initial capital outlays, but in general terms
24 those projects don't generate the same fuel
25 savings, so over the longer term you see a higher

1 fuel cost over the life of the project, so it
2 ultimately ends up being more expensive.

3 Q. And each of those scenarios is just a
4 natural gas scenario, there is no other fuel that
5 was --

6 A. (Mr. Major) That's correct.

7 Q. -- that was mixed into --

8 A. (Mr. Major) Yes.

9 Q. -- the comparison. You had mentioned
10 earlier, Mr. Major, I believe, the possibility of
11 adding two coal gasification combined cycle units
12 at the Polk County site; is that correct?

13 A. (Mr. Major) Yeah, Bob. When I talked
14 about the site certification, the mix of generation
15 that we were demonstrating before the DEP, in our
16 minds, the worst case scenario in terms of site
17 impacts, emissions and all was a scenario that
18 involved 1,000 megawatts of combined cycle units on
19 natural gas and 2,000 megawatts of IGCC, integrated
20 gas coal combined cycle on the site. And so for
21 the ultimate site impacts, we demonstrated the
22 impacts of that, that mix of generation.

23 Q. And you say that was from a worst case
24 environmental emissions scenario?

25 A. (Mr. Major) That's correct. In our

1 fuel cost over the life of the project, so it
2 ultimately ends up being more expensive.

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4 natural gas scenario, there is no other fuel that
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19 natural gas and 2,000 megawatts of IGCC, integrated
20 gas coal combined cycle on the site. And so for
21 the ultimate site impacts, we demonstrated the
22 impacts of that, that mix of generation.

23 Q. And you say that was from a worst case
24 environmental emissions scenario?

25 A. (Mr. Major) That's correct. In our

1 minds, what we would be allowed to build. I think
2 that we had done an analysis on pulverized coal
3 units, had made a determination that it would be
4 difficult to secure approval on going with
5 pulverized coal units, that IGCC was a clean coal
6 technology, that we could demonstrate minimal
7 environmental impacts. It had -- it had higher
8 environmental impacts than natural gas combined
9 cycle because there is greater water consumption.
10 The emissions are somewhat higher than natural
11 gas. So in our minds, it was --

12 Q. Emissions for?

13 A. (Mr. Major) For integrated gas combined
14 cycle.

15 Q. Were greater than the natural-gas-fired
16 combined cycle?

17 A. (Mr. Major) Yes.

18 Q. What particular -- what types of
19 emissions are higher?

20 A. (Mr. Major) I believe it was driven
21 primarily because of a lesser efficiency in terms
22 of the conversion of the fuel to natural gas. So
23 since the units are less efficient, even if you can
24 clean up the stack emissions, NOX being one of the
25 concerns, and sulfur dioxide, I think in terms of

1 actual emissions measurement, they can be kept at a
2 similar level, but I think the combined cycle on
3 natural gas efficiency is somewhat higher than
4 IGCC.

5 Q. And you mentioned water consumption. In
6 relative terms, what kind of assumptions did you
7 make as far as the water consumption associated
8 with a gasifier versus a combined cycle plant or a
9 natural gas-fired?

10 A. (Mr. Major) It's higher, but I can't --
11 I'd have to look back at our licensing records to
12 determine in terms of quantities how much higher it
13 was.

14 Q. But on orders of magnitude, do you have a
15 feel? Is it just slightly higher, is it twice as
16 much for the same output, or if you know?

17 A. (Mr. Major) I couldn't comment on that.

18 Q. Mr. Major, I'd like you to go through
19 this section -- this report section by section and
20 just briefly explain for the record what your
21 understanding of each section is, how it was
22 developed, to the extent you know.

23 A. (Mr. Major) There was an introductory
24 section that gave some history on the site
25 certification, the determining of need, and current

1 status of the project where we were at at the time
2 in February of 1994, which pretty much said that
3 the site can be developed, the units can compete
4 and recommendation to go forward with the units as
5 approved by the Public Service Commission.

6 Gave a background on the site selection.
7 Gave some background on the generation technology
8 selection, background on need. Site certification.
9 Status of where all the permits were at the time
10 this report was written. A summary of costs that
11 had been expended to date. A section on our
12 analysis on the competitive posture of the Polk
13 County unit if we went forward. Listing of some of
14 the site advantages. A listing of some concerns in
15 terms of the site.

16 Q. Let me stop you right there and just ask
17 one question. In terms of the concerns that you
18 listed back in 1994, two years down the road, have
19 any of them come to fruition?

20 A. (Mr. Major) No, sir, not in my opinion.

21 Q. And of the advantages that are listed in
22 that report, are they still applicable? Are there
23 any that are no longer applicable or things that
24 did not work out the way you'd hoped?

25 A. (Mr. Major) There was mention about the

1 potential for considering compressed air energy
2 storage at Polk in the future. I think over the
3 years that has -- that has, in our opinion, not
4 borne out to be beneficial.

5 And there was mention made about the --
6 the gas pipeline, Polk being the anchor for the gas
7 pipeline, the SunShine Pipeline, which is no longer
8 a factor. But no real surprises or disadvantages
9 or, you know, the basic advantages are still there.

10 We talked about the capital cost
11 competitiveness of the going forward with the Polk
12 units, the O & M cost competitiveness, then a
13 description of what the three alternative option
14 scenarios are. Comparisons on the cumulative
15 present worth revenue requirements. Described some
16 what-if scenarios. What was covered there, what if
17 the pipeline were delayed, what if the pipeline
18 were canceled, what if gas prices become
19 uncompetitive.

20 Q. That raises a question. What if gas
21 prices go through the roof? What would Florida
22 Power Corporation -- how would Florida Power
23 Corporation expect to address that contingency?

24 A. (Mr. Major) I think we had -- let me
25 refresh myself on this. I think we had assumed

1 that if natural gas prices became noncompetitive in
2 the future, the load would shift away from Polk
3 County to the rest of our system. So the Polk
4 units would not be quite as competitive on a
5 system-wide basis, that the other units would pick
6 up for the slack that Polk County then had. And it
7 was not considered a realistic scenario that
8 natural gas would be noncompetitive.

9 Q. And when you say noncompetitive in terms
10 of relative price to today's relationships, how
11 would -- what levels would the price of natural gas
12 have to reach before it would be considered
13 noncompetitive?

14 A. (Mr. Major) I'd have to defer that one to
15 Pob.

16 A. (Mr. Niekum) We have never been able to
17 pin that down to a solid number. One of the issues
18 becomes is at what price, what causes the -- what
19 were the other fuel prices at the time natural gas
20 became more expensive. So it's really that
21 differential in gas compared to the other fuels.
22 In general, the advantage of a gas-fired combined
23 cycle unit is it has a very good heatrate, which
24 gives it an advantage even though the price of gas
25 may be high, it still has an efficiency advantage.

1 Probably we have seen gas -- we have seen
2 distillate-fired combined cycle units be
3 competitive on our system. So if you were to make
4 a general rule of thumb, you could say that if gas
5 became as expensive as distillate oil, it probably
6 is on the fringe of not being a competitive fuel,
7 but what you find is that there is no clear break
8 point. It just becomes -- you try to adapt to a
9 new situation and like Eric says, you would then
10 try and sell the energy out of that unit at a lower
11 capacity factor and still take advantage of the
12 opportunity when it is competitive.

13 Q. Is it fair to say, then, it would operate
14 more as a peaking unit and less as an intermediate?

15 A. (Mr. Niekum) Yes. It would probably --
16 maybe not as a peaking unit but as a very low
17 capacity factor intermediate unit. And it wouldn't
18 be -- it wouldn't be as cost effective because you
19 would still have the fixed charges of pipeline
20 transportation and you would have the high gas
21 prices. You may to some degree substitute fuels
22 and burn some distillate oil in there if the prices
23 became very high. And then ultimately the site is
24 licensed to build a gasification plant. If the
25 prices of natural gas became extremely high, that

1 option would still be open to you as far as the
2 site is concerned.

3 Q. Do you have a feel for or an estimate of
4 what the relative price of natural gas would have
5 to be for gasification to be cost effective at this
6 facility?

7 A. (Mr. Niekum) I don't have any recent
8 numbers. A number of years ago, that question
9 would come up, and we would do some rather crude
10 studies to look at it, and it always was relatively
11 high, in the range of maybe \$6 a million MMBTUs,
12 but those numbers were never -- we always found
13 them to be quite high, and so we never really
14 explored it in detail because it wasn't well within
15 the range of what we thought the high end of gas
16 prices would be.

17 Q. In other words, it was higher than you
18 expected the highest -- than the high fuel price
19 forecast?

20 A. (Mr. Niekum) Right. In all likelihood.
21 I mean, I would never say never because you do see
22 high prices.

23 Q. I understand that. Life does change.

24 A. (Mr. Niekum) But we thought it was an
25 extremely low probability.

1 Q. Did you assign a specific number to it
2 or --

3 A. (Mr. Niekum) Not on the probability. We
4 would look at numbers on what we saw the cost of
5 gasification to be and then try and adjust gas
6 prices to try and find a break even point. And
7 even doing relatively crude studies, it showed very
8 high numbers that we didn't feel it was too likely
9 that that would occur.

10 Q. Is that \$6 a million BTUs at the
11 in-service, planned in-service date of the unit?

12 A. (Mr. Niekum) Yes. Those studies were
13 done assuming that when Polk came on line what
14 would gas prices have to be to make the
15 construction of a gasifier make sense.

16 Q. And that would be relative to the price
17 of coal or coal at the assumed price going forward
18 or holding it constant?

19 A. (Mr. Niekum) It would be depending on
20 what you thought the best feed stock for the
21 gasifier would be.

22 Q. Okay.

23 A. (Mr. Niekum) There were alternatives
24 there that you might look at some sensitivities to
25 pet coke or orimulsion or garbage or whatever

1 people had proposed that they could gasify as
2 economical.

3 Q. And so that was -- that \$6 price was
4 based on your best estimate of what a competing or
5 the cheapest potentially -- potential fuel for a
6 gasifier would be at that time?

7 A. (Mr. Niekum) Right.

8 Q. And what was -- if you know, what was the
9 cheapest alternative fuel stock that you were
10 considering, or did it change?

11 A. (Mr. Niekum) It changed. We -- there
12 were a number of relatively inexpensive feed stocks
13 that were considered, and pet coke and orimulsion
14 were the alternatives to very high sulfur coal.
15 Generally you had those three, and then there were
16 always trade-offs on the construction cost of a
17 gasifier that would either exclusively use one of
18 them or was capable of all three, so you had that
19 trade-off of fuel flexibility in the gasifier which
20 became more expensive. So it wasn't a very simple
21 analysis to just say it would be this price.

22 A. (Mr. Major) Bob, over I guess sometime
23 several years ago, we did a -- we didn't do a
24 detailed analysis. I'm not even sure if the
25 information is around. But Bob mentioned \$6 per

1 million BTUs. I recall in some of the stuff that I
2 got involved in that number was more like between 3
3 and 4, \$4 probably being a realistic number when we
4 looked at it at a time.

5 Q. Okay. If we could just continue with the
6 draft cost effectiveness analysis.

7 A. (Mr. Major) Yeah. We addressed again in
8 the front page of the report the water issues which
9 came up in terms of if there ever became a
10 groundwater shortage and addressed some
11 alternatives that we could get into there.

12 Attachment I addresses some task force
13 summaries where we had developed some pro and con
14 scenarios which were earlier described on the
15 advantages and disadvantages of going forward with
16 Polk, and it was just supporting information to the
17 report.

18 We developed some alternative build-out
19 scenarios for Polk County to determine where we
20 could achieve some up-front savings, and they
21 typically had trade-off with additional cost for
22 later development and they were described in here.
23 And that's in Section II we developed alternate
24 site development scenarios.

25 Attachment III was a comparison of

1 recently constructed power plant projects primarily
2 in the state of Florida, and what they went in at,
3 at a dollar per KW basis, and this was used to
4 demonstrate that the Polk County construction costs
5 were still competitive with anything that had gone
6 in the state.

7 Q. At that time on a dollar per KW basis,
8 what was Polk projected to cost?

9 A. (Mr. Major) I think at that time we were
10 looking at between \$600 and \$700 per KW installed.

11 Q. And that was for 470 -- two 235s?

12 A. (Mr. Major) Well, yeah, that was on a
13 dollar per KW basis, but it was looking at the two
14 235s.

15 Q. And when you say installed costs, what
16 costs to construct are included?

17 A. (Mr. Major) That would have included the
18 site development, the plant, the associated
19 transmission and substation facilities, escalated
20 including AFUDC.

21 Q. So in other words, that would be the
22 figure that would go into rate base?

23 A. (Mr. Major) Yes.

24 MR. ELIAS: Why don't we take about a
25 five-minute break.

1 (Brief recess.)

2 A. (Mr. Major) I'll go on with Attachment
3 IV included a capital cost estimate which was our
4 numbers in December of '93 for the two units
5 combined cost per KW was \$633 plus escalation of
6 43 million, so that would have put it somewhere
7 over \$700.

8 Attachment V was a --

9 BY MR. ELIAS:

10 Q. If I can stop you, how did the cost
11 estimates change between the time of the need
12 determination and the time of the study as far as
13 the capital? And if you're referring to an
14 exhibit, maybe we could pass that out.

15 A. (Mr. Major) I don't have copies.

16 MR. MCGEE: I can get you some copies.

17 BY MR. ELIAS:

18 Q. First of all, would you describe what
19 you're looking at. And we'll mark this as
20 Exhibit C.

21 (Deposition Exhibit No. C identified.)

22 A. (Mr. Major) I have a summary of estimated
23 costs for the units. And it gives the costs at the
24 time of the need hearings and then it gives year
25 end forecasts for the years '93, '94, and '95, and

1 has our most current forecast which was developed
2 May of '96.

3 MR. WILLIS: Bob, excuse me. Have you
4 marked another exhibit?

5 MR. ELIAS: Exhibit B is going to be the
6 cost effectiveness draft report that was done in
7 February of '94.

8 (Deposition Exhibit No. B identified.)

9 BY MR. ELIAS:

10 Q. And could you describe how the costs have
11 changed over time.

12 A. (Mr. Major) Okay. At the time of the
13 need hearings, as best I could, I took the
14 equivalent cost of two units instead of four and
15 included site development costs and showed that at
16 the '91 need hearings on an escalated basis with
17 AFUDC, we were looking at \$1,074 per KW. At the
18 end of '93, that was actually \$869 per KW. At the
19 end of '94, those numbers were \$611 per KW.

20 And I've got it '94 asterisk because
21 there was actually a period of time where we were
22 looking at an advanced turbine technology. We call
23 them the G units. And we had some discussions with
24 Westinghouse and had some pricing information from
25 Westinghouse. At the end of '94, we were

1 considering going with G technology units and had
2 reflected that at our year end estimates in '94.

3 At the end of '95, the total project cost
4 estimate was at \$600 per KW, and our current May
5 '96 forecast is \$580 per KW.

6 Q. What contributed to the decrease over
7 time in the expected installed costs?

8 A. (Mr. Major) I think following -- well,
9 several -- several factors. At the time of the
10 need hearings, we were -- we were estimating an
11 escalation rate of somewhere between 4-1/2 to 5
12 percent, so some of the influence would have been
13 actual versus estimated escalation. And the
14 primary --

15 Q. And one question, not to throw you off,
16 but the escalation rate has been lower than
17 anticipated in the need determination?

18 A. (Mr. Major) I believe from a personal
19 perspective, I believe that escalation, the
20 overall inflation has been less than what we would
21 have anticipated in '91, and we found market
22 pricing on the equipment to have significantly
23 improved over what our anticipations were. The
24 largest single contributor to reduced cost is in
25 the area of the plant itself, the power block

1 island and the equipment and installation.

2 Q. Between 1993 and '94, it appears that
3 there was a significant change, and you mentioned
4 the so-called G technology. Does that account for
5 a lot of the change between '93 and '94?

6 A. (Mr. Major) Between '93 and '94, that
7 accounted for a very substantial amount of the
8 change in -- the total dollars did not change, but
9 the output of the plant when we estimated it at the
10 end of '94 had risen from the 470 to a 2-on-1 G
11 technology unit would have been 700 megawatts of
12 output. So on a dollar per KW basis those unit
13 prices dropped significantly.

14 Q. And is that same change incorporated into
15 the 1995 figure, or did Power Corp. subsequently
16 decide to not pursue that option?

17 A. (Mr. Major) We -- we decided to not
18 pursue that option because of the significant
19 discrepancy between what we had received approval
20 for in our need hearings, the 470 megawatts versus
21 the 700 megawatts the G technology would have
22 provided us. But during the course of getting
23 proposals from our vendors and the subsequent
24 negotiations, we were successful in achieving
25 pricing on improved F technology that essentially

1 got us to the G unit pricing and got us very close
2 to the efficiency targets of the G units.

3 Q. Is it fair to say, then, that in terms of
4 measure of fuel efficiency, this plant will be more
5 efficient than was envisioned at the need
6 determination?

7 A. (Mr. Major) Yes.

8 Q. Okay. What -- can you describe in a
9 measure that people -- heatrate?

10 A. (Mr. Major) In terms of heatrate, I don't
11 have the exact numbers, but I'm assuming that at
12 the time of the need discussion. Do you have
13 those, Bob? Okay. We were -- well, we were
14 roughly at say 8,000 BTU per kilowatt-hour. And
15 our current projections are somewhere around 6,600
16 to 6,700 on a higher heating value.

17 Q. And I can never keep it straight. High
18 heat values are the ones that are usually lower?

19 A. (Mr. Major) They are higher. Okay.
20 Lower heating value is lower by about 11 percent.

21 Q. And what's the difference between the
22 two?

23 A. (Mr. Major) I can't give you a good
24 explanation on that.

25 Q. Okay. But for comparison purposes, the

1 high heat value number is the one that we should
2 use?

3 A. (Mr. Major) That's what we used
4 internally at the time, yes.

5 Q. Okay. That's what I want to understand.

6 A. (Mr. Major) That covers the cost
7 comparison.

8 Q. Were there any other significant
9 contributing factors to the changes in the
10 estimates? You mentioned the escalation rate, the
11 costs of a power block.

12 A. (Mr. Major) Our AFUDC calculations have
13 come down from what previously had been forecast at
14 the time of the need hearings.

15 Q. And those are functions basically of the
16 cost of capital; is that correct?

17 A. (Mr. Major) The timing of when the
18 capital expenditures are incurred, yes, sir.

19 Q. So was it the timing or the rate or the
20 capital costs or both?

21 A. (Mr. Major) I believe it was a
22 combination of both, the rate as well as a shorter
23 construction time and later expenditure of the
24 funds.

25 Q. How much did the construction time

1 shorten over the -- since the time of the need
2 determination?

3 A. (Mr. Major) I believe -- in terms of the
4 site development cost, site development timing, it
5 stayed about the same, but in terms of construction
6 time on the plant, we're looking at a 16-month
7 construction time period now. I'm not sure exactly
8 what it was at the need hearings, but it was
9 definitely longer.

10 Q. And how long would you -- strike that.
11 Did it become apparent in the 1994 time
12 frame or during -- does the 1994 cost estimate
13 reflect a shorter construction time frame?

14 A. (Mr. Major) No. I think in the '94 time
15 frame, it was the technology that drove the pricing
16 down, the G technology and the higher output. Our
17 AFUDC costs were still high in the '94 time frame,
18 so it would not have accounted for reduced
19 construction period.

20 Q. So the reduced -- when --

21 A. (Mr. Major) That was -- that started to
22 get addressed in '95, latter part of '95.

23 Q. And the planned in-service date of this
24 unit is still November of '98?

25 A. (Mr. Major) Yes, it is. Bob is pointing

1 out that we showed almost a three-year construction
2 duration at the need hearings.

3 Okay. Section V of Exhibit B is a --
4 it's a breakdown of the operating and maintenance
5 cost estimate. And we do a comparison. It's
6 actually a comparison of what we anticipated at
7 Polk County versus what we felt a competitor could
8 build a unit on a small parcel and not be burdened
9 with the site development cost that we were faced
10 with. And it defines the assumptions that went
11 into the operating and maintenance cost estimates,
12 and it's primarily a definition of the conditions
13 of certification that we were expected to comply
14 with coming out of site certification.

15 Attachment VI is a comparison of Polk
16 County construction, and it gives -- it gives a --
17 oh, okay. That's where we compare the three
18 options that we had previously discussed about
19 continuing forward with Polk as defined by the need
20 determination versus considering building the units
21 on a smaller site versus repowering our Higgins and
22 Turner units first. And it shows the cumulative
23 revenue requirements comparison between the options
24 that were considered in February of '94.

25 Attachment VII is a schedule of

1 projected purchased power payments if we considered
2 purchased power instead of construction of the Polk
3 County units.

4 Attachment VIII is the -- addresses some
5 of the natural gas scenarios where we looked at
6 delays of the pipeline, the availability of gas
7 supply, and there are some what-if scenarios in
8 terms of gas supply.

9 Attachment IX is more detail on the
10 regulatory compliance costs for operating the power
11 plant, which gets into more detail in terms of the
12 conditions of certification and the costs of
13 complying with those.

14 Q. And those are primarily or exclusively
15 environmental considerations?

16 A. (Mr. Major) Yeah. They address such
17 things as annual air compliance tests, continuous
18 emissions monitoring, waste water systems, drinking
19 water facilities, dam inspection, groundwater
20 monitoring, pollutant emissions fees, essentially
21 compliance costs for the units.

22 And Attachment X is again a buy versus
23 build consideration on purchased power versus
24 building the Polk County units and impact on the
25 ratepayers. And that covers the contents of this

1 exhibit.

2 Q. Okay. Once that report was completed,
3 was it reviewed by management?

4 A. (Mr. Major) Yes. There were meetings
5 held by -- with our senior management. And
6 following those reviews and some clarifying
7 questions, we proceeded on with the next phase of
8 project development, which was developing the
9 detailed site development drawings and then later
10 that year contracting for the site development
11 activities.

12 Q. So then when you say senior management,
13 was it presented to the board of directors?

14 A. (Mr. Major) No. It would have been at
15 the -- to my boss, who is senior vice president of
16 energy supply, and there were some -- I believe
17 the -- there was a strategic planning group at that
18 time that had some involvement and some
19 presentations to our president at that level.

20 Q. Okay. And you indicated next that you
21 began to begin with the site development?

22 A. (Mr. Major) Yeah. Completing -- well,
23 doing the detailed design for the site development
24 activities, putting together a request for proposal
25 to solicit bids for the actual site development

1 work, and evaluating those bids, and then we issued
2 a contract in the, I believe, third quarter of '94
3 to go forward with the site development work.

4 Q. Were you involved in the acquisition,
5 land acquisition activities for the Polk site?

6 A. (Mr. Major) Yes, I was.

7 Q. And when and from -- well, let's start
8 with when the site was identified as the most
9 appropriate site for Florida Power Corporation's
10 next unit addition. What did Florida Power Corp.
11 do at that time to secure the land?

12 A. (Mr. Major) We had some initial
13 discussions with the three property -- there were
14 initially three property owners involved, IMC,
15 Estech, that's spelled E-S-T-E-C-H, and U.S.
16 Agrichemical. And following the completion of the
17 site selection, we had initial discussions to
18 confirm the availability of the site in terms of
19 neither of those companies having additional needs
20 or limited needs for those properties for mining
21 purposes. And that there was an interest on the
22 owners to sell the property.

23 And there were negotiations that -- that
24 started prior to some discussions that happened
25 between the time the site was selected and the time

1 we went in for our need determination. Once the
2 need determination was approved by the Public
3 Service Commission, negotiations started in terms
4 of trying to negotiate a price in terms of the
5 contract, and those resulted in options being
6 secured to purchase the property, those options
7 being contingent upon our receiving site
8 certification approval and contingent on receiving
9 the necessary -- the permits in addition to the
10 site certification approval.

11 Q. When you say additional permits, do you
12 mean --

13 A. (Mr. Major) There were some federal
14 permits beyond the state permits that certification
15 would have provided us.

16 Q. Of the three entities that you mentioned,
17 how much in terms of acreage was sought from each?

18 A. (Mr. Major) Estech had roughly 2,500
19 acres that he had an interest in. IMC had roughly
20 4,700 acres. And U.S. Agrichemical had, I believe,
21 70 to 100 acres that he had an interest in.

22 Q. So the options to purchase these -- was
23 it three tracts?

24 A. (Mr. Major) Yes. Three tracts, one --
25 one tract from each owner.

1 Q. And the options would have been secured
2 in the 1992 time frame?

3 A. (Mr. Major) I would have to check on the
4 exact timing of when those options were executed.
5 It would have been in the '92, '93 time frame,
6 might have been as late as early part of '93.

7 Q. Did Power Corp. execute any of those
8 options in 1993?

9 A. (Mr. Major) No.

10 Q. So then is it correct that no land for
11 the Polk site was purchased before 1994?

12 A. (Mr. Major) That's correct.

13 Q. And was land purchased in 1994?

14 A. (Mr. Major) Yes.

15 Q. Okay. Would you -- what was the land
16 previously used for, and if there are differences
17 among the three tracts, let's --

18 A. (Mr. Major) The IMC properties, they had
19 been extensively mined. I'd say most of the
20 properties that we purchased from IMC had been
21 mined. And the majority of those properties had
22 been utilized by IMC as clay settling ponds or in
23 the case of one of the IMC parcels was intended to
24 be used as a clay settling pond.

25 Q. So had the land been reclaimed at that

1 time?

2 A. (Mr. Major) None of the IMC properties
3 had been reclaimed.

4 Q. Was reclamation required pursuant to the
5 terms of the permit?

6 A. (Mr. Major) There was reclamation
7 required on portions of the IMC parcels. I'm not
8 exactly sure on what percentage, but roughly a
9 third of the IMC properties had reclamation
10 requirements associated with them.

11 Q. And would you describe to the best that
12 you remember the specifics of the costs and terms
13 and conditions of the contract with IMC for
14 purchase of that particular parcel.

15 A. (Mr. Major) As I recall, there was --
16 there was an up-front contribution made to IMC to
17 relocate a clay slurry pipeline that would have
18 allowed for the clays to be deposited on properties
19 other than one of the parcels that we were
20 purchasing. We wanted to protect that parcel so
21 that we could develop that as a cooling pond and
22 have clean fill material that came out of there. I
23 believe that cost was roughly \$3-1/2 million.

24 Q. So that was for the cost of relocating
25 the pond?

1 A. (Mr. Major) Relocating a pipeline --

2 Q. Pipeline.

3 A. (Mr. Major) -- that they were intending
4 to deposit clays on the property, for them to
5 relocate the pipeline to deposit those clays
6 elsewhere, which preserved the nature of that
7 parcel for us.

8 And then in addition to that, there was
9 the cost of the property that was negotiated when
10 we secured the options, and what we actually
11 purchased the property for was roughly 900 --
12 somewhat over \$900 an acre. I think \$918 an acre
13 for the IMC.

14 Q. Was that for all 4,700 acres?

15 A. (Mr. Major) Yes.

16 Q. And as --

17 A. (Mr. Major) And then there were other
18 terms of the agreement which allowed IMC to mine a
19 relatively small parcel of the property and utilize
20 it through the year '98, I believe, which is an
21 area we call the phosphoria area, and there were
22 some terms in there where they during construction
23 agreed to accept some of the waters if we got into
24 wet weather and needed to deposit -- remove water
25 off of the construction site.

1 Q. And did Florida Power Corporation assume
2 the responsibility for reclaiming the lands?

3 A. (Mr. Major) Yes, we did. And I wouldn't
4 call that -- the design for the ultimate site
5 development which was submitted to DEP as part of
6 site certification pretty much defined the
7 enhancements that needed to be made, so it was
8 different from what IMC would have had to reclaim.

9 Q. In other words, is it fair to say that
10 because of Florida Power Corporation's uses or
11 planned use for the property, the reclamation plan
12 was different --

13 A. (Mr. Major) Yes.

14 Q. -- than it would have been?

15 A. (Mr. Major) Yes.

16 Q. Could you describe that in a little bit
17 more detail?

18 A. (Mr. Major) I believe that typically when
19 a mining company does reclamation, there is a
20 combination of uses that the land is reclaimed to,
21 like lakes, if they have mitigation requirements,
22 some wetlands, and in pasture are the typical
23 reclamation requirements. In IMC's case, part of
24 their properties would have been reclaimed to
25 pasture and part would have been wetlands.

1 When we assumed ownership of the
2 properties, the primary uses of the property were
3 going to be cooling pond, which would have involved
4 consolidating some of those clays and reinforcing
5 some of the dams to make them suitable for cooling
6 pond use. About half or about a third of the
7 properties would have been used for solid waste
8 disposal. In the event that we went with the IGCC
9 technology, we provided for the ultimate storage of
10 all the slag that may have been generated over the
11 life of the plant. So about a third of the clay
12 settling areas would have been consolidated and
13 used to store the combustion by-products, the slag.

14 And then approximately 1,400 acres of the
15 IMC properties were -- are going to be developed as
16 buffer areas along the eastern and southern portion
17 of the property. Along the eastern portion we've
18 got some wetland mitigation to do and some upland
19 forest to establish.

20 Q. The requirement for a buffer, whose
21 requirement is that?

22 A. (Mr. Major) That was a requirement
23 negotiated with state agencies, primarily DEP,
24 their Bureau of Mines divisions, and Game and Fish
25 were involved in that as well.

1 Q. And do you have specific site development
2 costs by parcel or estimated site development costs
3 by parcel, or do you have an aggregate?

4 A. (Mr. Major) I've got an aggregate that I
5 have brought with me. To achieve that aggregate
6 number, we do have a -- well, no, I think -- I
7 think I've also got an exhibit that breaks it down
8 to individual parcels. I don't believe it breaks
9 it down to specific, specific parcels.

10 Q. Okay. We'll work backwards. What's the
11 aggregate figure for site development?

12 A. (Mr. Major) Okay. Our current estimate
13 for land and site development including the land
14 purchase is \$62,687,000.

15 Q. And does that include all required
16 reclamation activities?

17 A. (Mr. Major) That includes all reclamation
18 activities through the establishment of the first
19 unit. There are some additional reclamation
20 activities that are longer term which involve the
21 consolidation of some of the IMC clay setting ponds
22 that -- that upon completion of reclamation will be
23 used as areas to capture rainfall and satisfy some
24 of the plant water needs and then would ultimately
25 be used for storage of combustion by-products, the

1 slag. I don't have a detailed estimate with me on
2 what those costs are, but those -- those would be
3 less than \$5 million.

4 Q. And those -- that approximately
5 \$68 million figure, that's in contemplation of a
6 300 -- excuse me, 3,000 megawatt eventual site
7 capacity?

8 A. (Mr. Major) That is correct. Now, there
9 will be some -- there will be some future site
10 development costs for expansion of cooling ponds
11 that will be in terms of timing, it will be driven
12 by the construction of future units. And I think
13 that would -- that would be after about 1,500
14 megawatts have been built on the current parcels.

15 Q. So then the current plan includes cooling
16 ponds that are sufficient to -- capable of
17 supporting additional generation at the site?

18 A. (Mr. Major) That is correct. And that
19 was driven primarily by the location of the dams
20 that were on the properties when we purchased
21 them. It was -- I mean, it -- from the cost
22 perspective, it was more economic to utilize
23 existing dams that were there than to make a
24 smaller cooling pond and cut back on the cooling
25 pond size.

1 Q. Got you. Okay. Let's go back to the
2 second parcel, the one you purchased from Estech.

3 A. (Mr. Major) That was approximately 2,500
4 acres. Most of that property had previously been
5 mined. Some about, I would say, roughly half --
6 roughly a third to a half of that property had
7 previously been used as clay settling ponds. The
8 remainder did not have any clays deposited on it,
9 and that was the preferred location where we could
10 actually develop the units themselves where there
11 were no clays and we could achieve satisfactory
12 foundations. Most of the property had -- was --
13 had almost met its reclamation requirements. In
14 other words, Estech was almost complete with their
15 reclamation plan for those parcels.

16 Q. And what was the price per acre for that
17 parcel?

18 A. (Mr. Major) That was roughly 1,500 per
19 acre.

20 Q. Were there any other significant terms or
21 provisions or conditions associated with that
22 transaction?

23 A. (Mr. Major) No. There was an area where
24 there was some concern about environmental
25 conditions where it looks like in phasing out of

1 their mining operations, they had deposited some
2 substances that we were suspicious of, so that was
3 broken out as a separate parcel that we didn't have
4 an obligation to purchase. And then after further
5 environmental studies, it was deemed acceptable by
6 the agencies, so we -- I think when we actually
7 closed on the property, we closed on the entire
8 2,500 acres.

9 Q. And was that it for that parcel in terms
10 of contingencies or conditions?

11 A. (Mr. Major) I believe so, yeah. There
12 was -- there was one other in addition to the 2,500
13 acres that was purchased for the plant site, as
14 part of the negotiations with the state agencies,
15 we were also required to establish a wildlife
16 corridor between -- I guess between two river
17 habitats, the Peace and -- I'm not sure what the
18 other river system is. And that involved the
19 purchase of 400 additional acres from Estech to
20 complete the wildlife corridor.

21 Q. Is that included in the 2,500?

22 A. (Mr. Major) No. That's in addition to
23 the 2,500, but those costs are included in the site
24 development cost.

25 Q. Okay. So the \$68 million includes the

1 cost of the 400 acres --

2 A. (Mr. Major) Yes.

3 Q. -- of wildlife corridor. The parcel that
4 you purchased from U.S. Agrichem?

5 A. (Mr. Major) U.S. Agrichem is a -- is a
6 small parcel that actually we call it a notch where
7 70 acres extended up into the -- along the southern
8 border. If you drew a straight line, IMC would
9 have a 70-acre notch protruding up into the
10 properties that we purchased from IMC. And in
11 terms of air modeling and impacts along the
12 boundaries of the property, it was determined that
13 it would be advisable to own that parcel. We still
14 have an option on that. We have not yet purchased
15 that.

16 That area was used by U.S. Agrichem as a
17 part of a clay settling pond. I believe it's still
18 being used as a clay settling pond. And that
19 option, I believe, provides for us to purchase that
20 when they are completed using it sometime in the
21 '98 time frame.

22 Q. And the purchase price for that parcel?

23 A. (Mr. Major) I think it's less than \$1,000
24 per acre. It is less than \$1,000 per acre, but I'm
25 not sure on the exact price.

1 Q. And do you anticipate there will be
2 reclamation activities required associated with the
3 purchase of that parcel?

4 A. (Mr. Major) Minimal, if any. I don't
5 anticipate any reclamation requirements.

6 Q. Any site development?

7 A. (Mr. Major) No.

8 Q. And when you said from an air modeling
9 perspective it would be worthwhile or be
10 appropriate to include that parcel?

11 A. (Mr. Major) Yeah. When you evaluate
12 your impacts of the units, that's typically done at
13 the property boundary. And with this notch
14 protruding into the southern boundary of our
15 property, I believe that in the event of full
16 build-out at 3,000 megawatts with IGCC, there was a
17 scenario where we may have exceeded the threshold
18 on the emissions at the boundary.

19 Q. Of the total site, approximately 8,000
20 acres, what portion required reclamation?

21 A. (Mr. Major) Well, ultimately in terms of
22 consolidating clay settling ponds, and to some
23 extent I would say that 90 percent of that would
24 have required reclamation. When we talk about
25 reclamation, it was altering the nature of the site

1 from what it was in when it was purchased.

2 Q. So that your definition includes
3 reclamation and site development?

4 A. (Mr. Major) Yes. Yes.

5 Q. Okay.

6 A. (Mr. Major) In terms of true reclamation,
7 I would consider that the buffer areas, which were
8 roughly 1,400 acres.

9 Q. In other words, where you're just going
10 to put the land back, quote, in its natural state
11 and then not do anything further with it?

12 A. (Mr. Major) Yeah.

13 Q. Okay. We were up to, I believe, letting
14 the contracts for the land and site development?

15 A. (Mr. Major) Yes. So those contracts
16 were issued in the, I believe, third quarter of
17 '94. The contractor mobilized, I believe, in
18 October of '94. And there has been ongoing site
19 development work going on since, since October of
20 '94. The contractor will essentially complete that
21 effort in August.

22 Q. So then the site will be ready to build
23 on in August?

24 A. (Mr. Major) Yeah. One of the critical
25 activities is to start filling the cooling pond for

1 it to be ready when the plant goes in-service. And
2 that's roughly a two-year effort to fill the
3 cooling pond. And that will start in August.
4 Physical plant construction will not start until
5 the May or June time frame of '97. In the latter
6 part of '94, we also issued requests for proposals
7 on the plant equipment to the four major equipment
8 suppliers, ABB, GE, Westinghouse, and Siemens.

9 Q. And put this in terms that I can
10 understand. Is Florida Power Corporation acting as
11 its own general contractor in this activity?

12 A. (Mr. Major) That -- when we issued the
13 request for proposal, we issued several options.
14 One was on the basis of the G technology, we wanted
15 to see what was available in terms of advanced
16 units and find out how those costs compared in
17 performance parameters compared against
18 conventional units. And then we also evaluated a
19 turnkey versus self-build approach.

20 So the requests for proposals were for
21 both conventional and advanced technologies, the
22 option to quote either, and alternative quotes for
23 turnkey build versus furnishing the material scope
24 only. And the material scope that we requested
25 from those suppliers were the two combustion

1 turbines, the two heat recovery steam generators,
2 and the steam turbine.

3 Q. And you say this would have been
4 issued --

5 A. (Mr. Major) That was issued in November
6 or December of '94. I believe we received
7 proposals back in February of '95. We went through
8 evaluations of the various alternatives and
9 prepared recommendations to our senior management
10 in the September of '95 time frame, and those were
11 approved, and then we did detailed conformance of
12 the contract documents and the contract specs with
13 the primary and alternate supplier and which
14 resulted in a contract being inked, I believe, in
15 March of '96.

16 Q. Now, in the unit configuration you
17 mentioned two combustion turbines, two heat
18 recovery steam generators, and one steam turbine.
19 Is that different from the need determination?

20 A. (Mr. Major) Yes, it is. And I'm trying
21 to think at what time frame this occurred. In the
22 need determination there was one unit 235 megawatts
23 that was approved for '98 and another unit in '99.
24 I believe in August of '95, sometime during '95 we
25 did an evaluation on a 2-on-1 configuration unit

1 putting out 470 megawatts versus two separate units
2 putting out 235 megawatts and did an economic
3 evaluation on that, worked with our planners, with
4 the result being that a decision was made to go
5 with a 2-on-1 combined cycle unit at a nominal 500
6 megawatts, which the additional capacity would be
7 brought on a year early in '98 rather than build a
8 second unit for '99.

9 Q. And you found that that path was less
10 expensive than staging -- than one in '98 --

11 A. (Mr. Major) Yes.

12 Q. -- and one in '99?

13 A. (Mr. Major) Yes, we did.

14 Q. In terms of cumulative present worth
15 revenue requirements differences, do you have a --

16 A. (Mr. Major) I will have to gather up
17 that data. I do not have that with me.

18 Q. Was that decision made before the
19 requests for proposals were issued?

20 A. (Mr. Major) No. That decision was not
21 made until ninety -- well, let's see. It was while
22 the RFP was outstanding, while we were evaluating
23 the response to the proposals.

24 Q. I know my friends in the Division of
25 Electric and Gas are going to want to see that

1 revenue requirements comparison if you have it or
2 the information on the change.

3 MR. MCGEE: Do you want to mark that as a
4 late-filed?

5 MR. ELIAS: Yeah. Let's mark it as
6 Late-Filed Exhibit D.

7 (Late-Filed Deposition Exhibit No. D
8 identified.)

9 BY MR. ELIAS:

10 Q. And give it a title of cost effectiveness
11 evaluation, 2-on-1 configuration?

12 A. (Mr. Major) Yeah.

13 Q. Now, you said the contracts had been
14 inked. What finally did Power Corp. opt to go with
15 in terms of suppliers and choices of turnkey versus
16 materials?

17 A. (Mr. Major) We opted to go with a
18 self-build approach, not turnkey, where we would
19 purchase the major equipment from one supplier, and
20 that -- that supplier ultimately wound up being
21 Westinghouse. They will furnish the two combustion
22 turbines, the two heat recovery steam generators,
23 and the steam turbine. And we have a contract with
24 Black & Veatch for the design and construction
25 management assistance for the plant itself.

1 The construction -- we're currently
2 evaluating the mode of construction, whether we
3 will issue separate work packages or go with a
4 general contractor or act as our own constructor.

5 Q. And you indicated a 16-month approximate
6 lead time. When do you expect to begin
7 construction, actually breaking ground?

8 A. (Mr. Major) In June of '97 time frame.

9 Q. If you would, describe generally for me
10 how the contracts for the purchase of the equipment
11 are structured particularly with regard to
12 cancellation penalties, opportunities to
13 renegotiate different aspects of the contracts
14 along the way. Are you based on -- is Power Corp.,
15 based on the contracts that were signed in March
16 1996, committed to building this unit? And I mean,
17 what kind of penalties would you incur if it was --
18 if it suddenly appeared that building this unit
19 might not be the way to go?

20 A. (Mr. Major) We would -- we would be faced
21 with penalties if we opted to cancel the contract
22 once it was signed, and we would be at risk for any
23 material commitments that Westinghouse would make
24 from their subsuppliers and engineering work, but
25 we were within the -- we were essentially within

1 the lead time delivery time of the equipment
2 components, and their -- their design and
3 manufacturing cycle. So it was -- I mean, that was
4 a -- when we signed that contract, there was a
5 commitment to go forward with the plant
6 construction.

7 Q. And in terms of the timing and magnitude
8 of the penalties, could you -- I don't want to ask
9 you to reveal any confidential information, but
10 generally speaking when -- if today in June of 1996
11 you decided that this project was no longer viable,
12 what kind of penalties would you incur?

13 A. (Mr. Major) Those I would have to look
14 at the details of the contract. Typically there's
15 a payment schedule and a cancellation schedule
16 where if you cancel out, describes what the
17 obligations are.

18 Q. So that that's fixed by contract?

19 A. (Mr. Major) By contract terms.

20 Q. What other activities have taken place
21 besides the actual construction of the power block
22 in terms of the contracting for it? What other --

23 A. (Mr. Major) Well, we're in the process
24 now of evaluating the mode of construction and
25 preparing our request for proposal to go to a

1 general contractor. We have established a target
2 price at which we jointly with Black & Veatch feel
3 we could self-perform the construction or do it in
4 terms of work packages. And we will solicit bids
5 on the construction portion and then do an
6 evaluation how we go forward with the
7 construction. That's currently in process.

8 There is detailed engineering ongoing now
9 with Westinghouse for providing the sufficient
10 detail that Black & Veatch needs to balance the
11 plant interfaces to the Westinghouse scope of
12 equipment supply. And we're wrapping up the site
13 development construction that's ongoing right now.
14 Those are -- those are pretty much the activities.
15 Detailed design on the Black & Veatch end of it
16 will start in the September time frame of this
17 year.

18 Q. And how long -- well, obviously most of
19 that will be finished by June of 1997?

20 A. (Mr. Major) Yes.

21 Q. Good thing.

22 A. (Mr. Major) And starting in September
23 we'll be issuing the requests for proposals for the
24 balance of the plant equipment.

25 Q. What other equipment besides what's been

1 described will be needed to be purchased?

2 A. (Mr. Major) Oh, all equipment beyond the
3 combustion turbines, the heat recovery steam
4 generators, and the steam turbines. So the control
5 systems, blower feed pumps, piping, a lot of
6 electrical equipment, step-up transformers,
7 significant scope of supply.

8 Q. And all those things were included in the
9 approximately \$580 per KW expected installed cost?

10 A. (Mr. Major) Yes. Yes, they were.

11 Q. And that's true of everything that we've
12 talked about here --

13 A. (Mr. Major) Yes.

14 Q. -- all in that figure. Okay. Now, is
15 there anything else that you can think of about the
16 construction of the plant or the current estimates
17 of costs that we haven't covered?

18 A. (Mr. Major) Well, let me -- there's one
19 other piece that's ongoing now. And to satisfy our
20 water requirements, we've got an agreement with the
21 City of Bartow for tying into one of their
22 treatment plants and receiving treated effluent
23 into our cooling pond. And the construction of the
24 pipeline connecting their treatment facility with
25 our cooling pond is ongoing right now. And that

1 should be complete in August when we expect to
2 start receiving water into the treatment pond. But
3 those costs are included as well in the site
4 development cost.

5 Q. Other than those that we previously
6 discussed, did you have any other documents
7 reflecting the current costs of the plant?

8 A. (Mr. Major) I've got Exhibit C, which on
9 an annual basis describes how the estimates
10 compare. There is a -- previously at Commission's
11 request there was a breakdown of the site
12 selection, site certification, site development
13 costs. I've got an update of those numbers.

14 MR. ELIAS: Could we mark that as Exhibit
15 E.

16 (Deposition Exhibit No. E identified.)

17 A. (Mr. Major) And I've got a detailed
18 listing of the total project cost breakdown, but
19 there are some sensitivities in there because it
20 breaks it down by contract, and it would have the
21 Westinghouse contract amount, and I would like to
22 have that treated as confidential.

23 MR. ELIAS: Okay. Well, we'd certainly
24 like to see it. We'd like to afford the -- protect
25 the confidentiality of the material. You want to

1 go off the record?

2 MR. McGEE: Yes, if we could for a
3 minute.

4 (Discussion held off the record.)

5 MR. ELIAS: By agreement, Florida Power
6 Corp. will produce a late-filed exhibit reflecting
7 the detail of current project costs and summarized
8 in such a way so as not to specifically identify
9 confidential proprietary information.

10 (Late-Filed Deposition Exhibit No. F
11 identified.)

12 BY MR. ELIAS:

13 Q. Mr. Major, I think the last area that I
14 want to discuss with you is the whole question of
15 how this unit is going to fit into FPC's system in
16 terms of a revenue requirement associated with the
17 facility. You pretty much detailed the operating
18 cost. Have you prepared a cumulative present worth
19 revenue requirements associated with this unit
20 based on current cost information or cost
21 projections?

22 A. (Mr. Major) We have -- when you say -- in
23 other words, a cost projection on what most of our
24 cost is going to be out of the unit?

25 Q. Yes, sir.

1 A. (Mr. Major) That has been done in our
2 financial section within our department that I
3 don't have that with me.

4 Q. Can you make it available?

5 A. (Mr. Major) Yes.

6 MR. ELIAS: I'd like to ask for that as
7 the next late-filed exhibit.

8 MR. MAJOR: What about the issue of
9 sensitivity?

10 MR. MCGEE: Off the record.

11 MR. ELIAS: Sure.

12 (Discussion held off the record.)

13 MR. ELIAS: We've identified one more
14 late-filed exhibit which will yield the cost of the
15 unit cents per kilowatt-hour based on current cost
16 estimates, fuel estimates, and operating and
17 maintenance expected costs. And that will be
18 Exhibit G.

19 (Late-Filed Deposition Exhibit No. G
20 identified.)

21 BY MR. ELIAS:

22 Q. Do you have a feel generally speaking on
23 the costs on a cents per kilowatt-hour or dollars
24 per megawatt-hour basis in the first year of
25 operation?

1 A. (Mr. Major) Well, it will be somewhere
2 between \$30 and \$35, less than 35, but I'd need to
3 take a look at the reports that we have.

4 Q. But you're comfortable that that's the
5 range that it's in?

6 A. (Mr. Major) Yes.

7 Q. It's 30, 35?

8 A. (Mr. Major) Yes.

9 Q. And that's based on expected gas prices
10 in the most recent fuel forecast?

11 A. (Mr. Major) Plus the capacity factors to
12 be operating.

13 Q. And that's based on an economic dispatch
14 on FPC's system?

15 A. (Mr. Major) Right.

16 Q. Mr. Niekum, you've not had a chance to
17 say very much, and I think I'm getting ready to
18 change that. Your current job title is the manager
19 or director of fuels department?

20 A. (Mr. Niekum) Director of fuels supply.

21 Q. And how is the fuels supply department
22 organized at Florida Power Corporation?

23 A. (Mr. Niekum) The department consists of
24 me as director, and then I have three principal
25 buyers in the department, one with the

1 responsibility of purchasing coal and heavy oil for
2 our steam plants, one buyer responsible for natural
3 gas purchases, and one buyer responsible for No. 2
4 oil, the light oil for our peaking plant. And then
5 we have three support people within the department,
6 one that concentrates primarily on oil, one that
7 does the daily gas buying, and then a department
8 support specialist to handle some of the clerical
9 responsibilities. And the department reports to
10 the senior vice president of energy supply.

11 Q. And who is that individual?

12 A. (Mr. Niekum) That's John Hancock.

13 Q. Florida Power also has a fuel subsidiary
14 or Florida Progress has a fuel subsidiary, Electric
15 Fuels Corporation. Are you familiar with that
16 entity?

17 A. (Mr. Niekum) Yes.

18 Q. How does your department interact with
19 Electric Fuels?

20 A. (Mr. Niekum) Electric Fuels is
21 responsible -- is responsible for supplying coal to
22 our Crystal River site. They supply coal to us and
23 to other utilities and other companies, but they
24 are our exclusive coal supplier for the Crystal
25 River site.

1 Q. And where does most of the coal for that
2 site come from?

3 A. (Mr. Niekum) It comes from mines in West
4 Virginia, Kentucky. They may occasionally buy spot
5 cargos from imported coal or from other mines
6 depending on where they find it, but primarily from
7 West Virginia and Kentucky.

8 Q. Generally speaking, of the fuels that --
9 the coal that you buy from the West Virginia,
10 Kentucky region, what percentage of the cost that's
11 eventually passed on to the ratepayers is for the
12 commodity itself and what percentage is
13 transportation at today's prices? Or ask the
14 question another way: What does it cost to get the
15 fuel down, down here?

16 A. (Mr. Niekum) I don't have the exact
17 numbers. It depends somewhat on our mix of barge
18 and rail transportation, but probably a rule of
19 thumb would be approximately half the cost is
20 transportation, but that's -- that's a variable
21 depending on exactly what the mix is.

22 Q. And obviously if the price goes up, the
23 price of transporting it is not going to go up as
24 quickly, one would hope?

25 A. (Mr. Niekum) Well, that's always hard to

1 say. That depends on what the driver is. If all
2 fuel prices go up and the transportation is driven
3 by transport fuel prices, there's a possibility
4 that could happen, but if that isn't really the
5 driver, it's maybe an environmental constraint on
6 coal mining, then what you said is true.

7 Q. Is your department responsible for
8 preparing Florida Power Corporation's fuel price
9 forecast?

10 A. (Mr. Niekum) We -- we produce the fuel
11 forecast, although it is produced from a variety of
12 inputs, including one from Electric Fuels as far as
13 their price forecast for coal and their current
14 purchase arrangements that they have. We depend on
15 them to do the fuel or the coal price forecast.
16 The oil and gas is done primarily through a
17 consulting service that we use, but we do also have
18 our own judgment on certain aspects of the cost of
19 transportation and just our own insight as to what
20 we know about what kind of prices we may pay.

21 Q. And prior -- you assumed your current
22 position in March of 1995; is that correct?

23 A. (Mr. Niekum) That's correct.

24 Q. Before you, who was responsible or who
25 was the director of the fuels supply department?

1 A. (Mr. Niekum) The previous director's name
2 was Norman Davis.

3 Q. And do you know how long he was in that
4 position?

5 A. (Mr. Niekum) I believe he came here
6 approximately in November of 1993 and then left in
7 March of 1995.

8 Q. And before Mr. Davis, who was the
9 director of the fuels supply department?

10 A. (Mr. Niekum) The position was vacant, I
11 believe, for about -- I'm not sure of the exact
12 timing -- about 18 months, and then Dale Williams,
13 who is the current principal buyer responsible for
14 coal and oil, was the acting director during that
15 time period.

16 Q. I'm sorry. What was the name again?

17 A. (Mr. Niekum) Dale Williams.

18 Q. So then Mr. Williams would have been
19 responsible for the 1991, '92 forecast?

20 A. (Mr. Niekum) Yes. Dale generally took
21 the responsibility of producing those fuel
22 forecasts. I believe at that time he reported to
23 the director. And I just went blank on his name.

24 MR. MCGEE: Don Roland.

25 A. (Mr. Niekum) Don Roland, who was the

1 director at that time. So he has since retired
2 from Florida Power, but he would have been the
3 director at the time.

4 BY MR. ELIAS:

5 Q. So essentially all fuel price forecasts
6 are developed either from Electric Fuels for coal
7 and consultants for all other fuels?

8 A. (Mr. Niekum) Over the years they've been
9 done different ways. Generally Electric Fuels has
10 been the primary input on coal forecasts. Oil and
11 gas have been done internally. They've been done
12 through taking consultants' reports pretty much at
13 face value. They've been done with taking several
14 consultants' reports and aggregating them. So
15 there has not been any real one consistent
16 methodology on fuel forecasts.

17 Q. Does Florida Power Corporation prepare
18 one fuel price forecast per year or different fuel
19 price forecasts for different purposes? How does
20 the planning cycle work?

21 A. (Mr. Niekum) We generally produce fuel
22 forecasts on an as-needed basis. And that can be
23 the driver to do a fuel forecast can be, one, you
24 may begin a planning cycle, for instance, in '93
25 when we had the necessity to do an integrated

1 resource plan or in 1991 when we had to do the need
2 determination. So some driver like that would
3 cause you to do a long-term fuel forecast.
4

5 Or there could be significant changes in
6 the market which would lead you to believe your
7 current fuel forecast is outdated or incorrect. Or
8 you may be going through some kind of business
9 planning issues and there's an internal need to do
10 a new fuel forecast.

11 The other driver is that fuel adjustment
12 proceedings every six months require that we relook
13 at the fuel forecast and prepare a short-term
14 forecast every six months for that -- for that
15 proceeding.

16 Q. The subpoena that you were issued asks
17 you to bring documents reflecting Florida Power
18 Corporation's annual fuel price forecast for the
19 year 1996 including all fuel price forecasts used
20 and evaluating the cost effectiveness of the Polk
21 County combined cycle generating facility. Do you
22 have those?

23 A. (Mr. Niekum) I have found as many of
24 those that were readily available in the time
25 frame, which include forecasts from our most recent
May 3, '96, back to one forecast that was done in

1 April of 1990. And these include both the
2 long-term forecasts and the fuel adjustment
3 short-term forecasts.

4 I'm not 100 percent confident I have
5 captured every one, particularly in the '91, '92
6 time frame because record keeping really didn't go
7 back that far, and until we went through record
8 storage, I wasn't sure I would find it. The one
9 that seems to be missing is the one that was
10 actually used in this need determination document,
11 but it has the fuel forecast in it as an appendix,
12 but I don't have the original document in this
13 stack.

14 MR. ELIAS: I'd like to get those marked
15 as the next exhibit. H, I believe it is.

16 (Deposition Exhibit No. H identified.)

17 MR. MCGEE: Bob, just so we're clear, the
18 request attached to the subpoena talks about the
19 annual fuel forecast, and as the witness indicated,
20 we don't really have an annual fuel forecast, so
21 he's provided more than one.

22 BY MR. ELIAS:

23 Q. Does Florida Power Corporation forecast
24 the costs of petroleum coke?

25 A. (Mr. Niekum) Yes. We are occasionally

1 asked to evaluate alternatives that may use
2 petroleum coke. And you'll see in some of those
3 forecasts there are some forecasts for petroleum
4 coke.

5 Q. Are the same individuals that are
6 responsible for -- how are the petroleum coke
7 forecasts prepared?

8 A. (Mr. Niekum) Generally Dale Williams, who
9 is responsible for the forecast, will do some
10 market surveys. He may also consult with Electric
11 Fuels to get some shipping charges or see where
12 sources of petroleum coke may be available. So he
13 is generally the one that would produce the
14 petroleum coke forecast. In general the consulting
15 reports we don't really address it through that.
16 It would be done through our own surveys of the
17 market and whatever input we can get through
18 Electric Fuels.

19 Q. Would you describe in general terms FPC's
20 current beliefs about the long-term trends in fuel
21 price forecasts. Which fuels do you see escalating
22 in price? Which fuels do you see in short --
23 potentially short supply? Which fuels do you see
24 as maybe subject to increased price pressure based
25 on Clean Air Act compliance or other internal

1 requirements? I just -- I want to understand what
2 Florida Power Corporation's long-term expectations
3 are for the relative price and the absolute price
4 of the primary fuels that we've discussed here.

5 A. (Mr. Niekum) To try and answer that in a
6 very general sense would be that our estimate of
7 fuels is that they are going to be a commodity
8 market where most fuels will compete closely with
9 each other and that certain fuels like coal will
10 remain relatively stable and the prices will remain
11 relatively flat, but fuels like gas and oil are
12 likely to have wider price swings but nevertheless
13 will never get too far out of line because of the
14 nature of the supply. Generally the supply of oil
15 on a world scale seems to be oil is very
16 plentiful. So while you might have short-term
17 market fluctuations, it's likely to come back into
18 balance relatively quickly.

19 The look at natural gas is pretty much
20 the same way, that the improvements in exploration
21 and the size of the wells being explored will lend
22 a reasonable supply of natural gas over time, and
23 while you may see individual price spikes or
24 periods of high prices or low prices, generally the
25 price of gas will be relatively stable, and that

1 there should be a closing of the gap between fuel
2 prices. Fuel prices will remain competitive. You
3 won't see one getting wildly out of line with
4 another.

5 Q. Do you believe that natural gas will
6 maintain a constant or more or less constant
7 differential between the price of natural gas and
8 the price of coal?

9 A. (Mr. Niekum) Probably evaluated over the
10 long term, yes, but certainly depending on what you
11 consider short-term, you may find periods of time
12 where for whatever reason you might find natural
13 gas become either cheaper than coal or very close
14 to coal and then at other times be extremely
15 expensive, but I think over the long term, you'd
16 say the differential would stay fairly constant.

17 Q. Included in those scenarios, are there
18 base case high and low price forecasts, or is this
19 just pick a point and this is it?

20 A. (Mr. Niekum) Depends on the individual
21 forecast. On the fuel adjustment short-terms it's
22 just a flat point. On most of the long-term
23 forecasts there's a high, medium and low. Some of
24 them, when you look through the documents, you'll
25 find that it started out with just a base point and

1 then a request was made for a high, medium and low,
2 and you'll see a letter where it had an addendum
3 for whatever particular study was done, somebody
4 wanted additional information or more variations
5 around the forecast. So in general the long-term
6 forecast had a high, medium and low and the
7 short-term ones had a point forecast.

8 Q. All other things being equal or all other
9 things unchanging, if the differential between the
10 price of coal and natural gas increases, what types
11 of generating alternatives are favored?

12 A. (Mr. Niekum) Depends on the load you're
13 serving. If all things are equal and you're
14 continuing to serve base load, I think obviously at
15 some point if the price of gas diverges from coal,
16 there is a point where you would want to look at a
17 coal-based technology.

18 What you may do as a practical matter is
19 rearrange your generation plan to adapt to the new
20 circumstance, you may make your gas-fired unit now
21 work intermediate or peaking and then add a coal
22 unit as opposed to trying to convert the original
23 unit to coal. But in general once the price
24 differential gets wide enough, it would make sense
25 to go to the lower-cost fuel eventually.

1 Q. Has FPC considered that in the context of
2 its Polk unit addition?

3 A. (Mr. Niekum) Well, one of the purposes of
4 having the Polk site was to have a site capable of
5 coal technology, and the site has been licensed to
6 allow for the introduction of coal gasification.
7 So as an ultimate backstop to high gas prices or if
8 gas simply became unavailable, then the facility is
9 there to either convert the existing units to coal
10 gasification or construct a coal gasification plant
11 there.

12 Q. What loss -- what costs and loss of
13 efficiency, if any, would be incurred in converting
14 the existing facilities to coal gasification?

15 A. (Mr. Niekum) I don't know enough of the
16 technical details, but I believe there are some
17 technical differences between a combined cycle unit
18 designed to burn natural gas and designed to burn
19 synthetic natural gas, but I'm not entirely sure I
20 know the magnitude of those modifications and how
21 different it would be. It's my understanding that
22 it isn't -- it isn't like rebuilding the unit, but
23 nevertheless there is a cost to using a fuel that's
24 a little different than what the unit was initially
25 designed to burn.

1 Q. Were you yourself responsible for
2 preparing any of the petroleum coke fuel price
3 forecasts?

4 A. (Mr. Niekum) Not directly. Dale Williams
5 does report to me, and he was responsible for
6 gathering the data on petroleum coke. But I didn't
7 directly deal with too many of the vendors on
8 exactly what their pricing structure would be.

9 Q. So that is it fair to say that you don't
10 have a detailed knowledge of petroleum coke?

11 A. (Mr. Niekum) I don't have a detailed
12 knowledge of it in terms of pricing and exactly
13 what the delivered cost would be and how to project
14 it out. I have a general knowledge of where it's
15 produced and how we would use it in our plants and
16 some of the tests that we conducted on our plants
17 to use it.

18 Q. You have conducted tests on your plants
19 to evaluate the petroleum coke?

20 A. (Mr. Niekum) Yes. We did a limited study
21 at our Crystal River plant to burn -- do a test
22 burn of petroleum coke at that plant and did some
23 environmental tests on it to see if it were both
24 technically feasible and would stay within our
25 environmental permits.

1 Q. And this is in an open stack, as it were,
2 application; correct?

3 A. (Mr. Niekum) Yes.

4 Q. You didn't look at gas -- you haven't
5 performed any studies with respect to gasifying
6 petroleum coke?

7 A. (Mr. Niekum) We haven't looked at any
8 from a technical end. We have talked to vendors
9 about the possibility of using it in a gasification
10 plant as a feed stock as part of the general
11 discussions about whether gasification would work
12 on our system. And it makes a difference in the
13 economics depending on what you think the price of
14 petroleum coke is as to what the value of the
15 gasification process would be.

16 Q. And did you reach any conclusions as a
17 result of those discussions?

18 A. (Mr. Niekum) In general on our system, we
19 didn't see that the gasification process would make
20 sense on our system when we looked at the
21 alternatives that we had available to us.

22 Q. And different systems could be different
23 though?

24 A. (Mr. Niekum) Yes.

25 Q. What differences do you think would

1 drive -- would favor the cost effectiveness of a
2 petroleum coke or gasification application?

3 A. (Mr. Niekum) It would depend a bit on
4 what your existing generation mix is now, how well
5 it would -- how well it would compete against your
6 existing units. It would depend a little bit on --
7 well, it would depend a lot on what kind of load
8 you intended to serve. If you had a high capacity
9 factor load, gasification would probably look
10 better than with a low capacity factor load.

11 And it would depend on a bit of just how
12 your fuel delivery system works, where the plant
13 was located, what it would cost you to get the fuel
14 there. It would improve the economics. I guess
15 the primary things would be how it fit in your
16 generation mix and what type of load you were
17 serving.

18 Q. I want to turn just briefly to fuel
19 inventory. What levels of fuel inventory does FPC
20 maintain for its Crystal River coal-fired plants in
21 days burn?

22 A. (Mr. Niekum) It varies a bit from time of
23 the year, but in general we look for around 16 to
24 20 days as being reasonable.

25 Q. And that is on the ground?

1 A. (Mr. Niekum) Yes.

2 Q. And I would imagine at any given point in
3 time you've got some inventory floating its way
4 down the river; is that true or --

5 A. (Mr. Niekum) In general we would have
6 some at our IMT terminal in New Orleans, and we
7 also have unit trains that are shoveling the coal,
8 so those trains are constantly in motion bringing
9 the coal in, so there's always some on the way.

10 Q. Is that also the actual level that -- is
11 20 days the target level, or is that what you've
12 achieved?

13 A. (Mr. Niekum) Generally right now we're at
14 that level. The targets range -- I'm trying to do
15 a calculation in my head -- probably from maybe 35
16 days. We've been that high. Last year we had a
17 very high inventory that we had to try and remove.
18 But we would like it to be somewhere in the 16- to
19 20-day range, but we may, say, going into the
20 summer want it to be 25 or 30 days, particularly
21 when you're going into summer storm season, it's
22 advisable, and you're also into the heavy burn
23 period at that time. When you go into the fall,
24 you may want your inventory to drop because you
25 really don't have the need for it.

1 Q. Does the level of inventory have an
2 impact on the reliability of the system?

3 A. (Mr. Niekum) Well, I think one thing that
4 maybe I didn't make clear is we're kind of just
5 talking with coal inventories right now, but it
6 depends on all the different units have different
7 requirements. The coal units we can think in terms
8 of anywhere from 15 to 30 days; however, you might
9 want to look at your inventory.

10 For oil plants, we may look at, again, 12
11 days as being supply there, because a lot of times
12 those units run at low capacity factors, and if you
13 carried a high inventory, it may sit there for a
14 month or two carrying a very high inventory, and
15 you don't really expect to burn it.

16 On the peaker sites, you think more in
17 terms of hours of operation, since they normally
18 don't run 24 hours a day, so you would think more
19 in terms of peaker sites of maybe 30 hours as
20 opposed to 30 days.

21 So to the degree the reliability is
22 affected, obviously if you ran out of coal, that's
23 a more serious problem than running out of oil, and
24 that's more serious than a small peaker site
25 running out of oil. In general, you don't want

1 that to ever happen, but there is a certain point
2 where you're willing to take some risk on some of
3 your smaller sites that if you had an extraordinary
4 circumstance, that site may run out of fuel.

5 Q. How does FPL -- FPC consider
6 uncontrollable unforeseen events in maintaining its
7 inventory levels for various fuels?

8 A. (Mr. Niekum) In general, we would want to
9 ensure that our coal supply is secure, since that's
10 the main -- our main energy base. The unforeseen
11 event depends on exactly what it is and how long we
12 think it would take us to recover. Some of our
13 plants are dual fueled. So one of our concepts is
14 to be able to use an alternative fuel in the event
15 that the supply is interrupted, and dual fuel
16 plants would be those that are capable of oil or
17 natural gas.

18 Q. Has Florida Power Corporation experienced
19 any delay in obtaining fuel being transported
20 across the Gulf of Mexico in say the last five-year
21 time frame?

22 A. (Mr. Niekum) Yes.

23 Q. Which fuel types and what delays?

24 A. (Mr. Niekum) Hurricane season last summer
25 was an example where almost all the fuels were

1 interrupted at least for a period of time. We had
2 the barges from our IMT terminal in New Orleans
3 that brought in barge coal were tied up. They
4 couldn't sail in the Gulf of Mexico. The same was
5 true of our six oil which comes from Houston and
6 New Orleans on barges was held up and it couldn't
7 come in.

8 The natural gas platforms were shut in
9 due to the hurricane, and so some of the gas
10 supplies were at least being constrained. There
11 was still gas, but there wasn't as much. We also
12 found that there was flooding in Georgia, and some
13 of the railroads were not able to get south, and so
14 there was a tie-up on the railroads. And while we
15 didn't close our nuclear plant, there was some
16 alert there because the hurricane was nearby and
17 there was some likelihood that we may have to shut
18 in the nuclear plant.

19 Q. That was not based on a lack of fuel
20 availability though, was it?

21 A. (Mr. Niekum) That was kind of -- that was
22 an operational concern. But there was a case
23 where, yes, all the fuels at that time, I think it
24 was Hurricane Opal that that occurred. And so
25 those kind of interruptions happen. Certain times

1 of the year there is fog in the Gulf of Mexico, and
2 the barges just are delayed. It takes them longer
3 to load. It takes a while until they -- once
4 they're loaded, they can't get out. And you find
5 these kind of delays happen. There can be problems
6 on the river system. In the cold winter there were
7 some ice problems on the river, and so the
8 deliveries down the river were held up. In general
9 they aren't long-term, but they certainly do
10 happen.

11 Q. During the last five years, has FPC ever
12 come close to running out of a particular fuel
13 based on supply interruptions or other
14 circumstances?

15 A. (Mr. Niekum) We have run close
16 particularly on small peaking sites. In general
17 there's usually a workable solution around that.
18 We can either run other plants. There might be
19 some economic dispatch penalty, but we can buy --
20 run other plants. There may be purchased power
21 available that we would displace running those
22 plants and only use them for the absolute hours
23 that we needed to.

24 So you can run low on fuel, but generally
25 you have circumstances that you can mitigate it.

1 You may pay a premium to buy more truck
2 transportation to get an emergency supply in. So
3 it's -- you seldom run out of fuel, but you may
4 occasionally run into cost situations where you
5 have to pay a slight premium to get the fuel in to
6 match your need.

7 And so we have never really run out of
8 fuel, but we have run into situations where we had
9 to scramble to get enough fuel because of an
10 unexpected burn or a unit failure or some
11 circumstances like that.

12 Q. When the Polk County facility was
13 certified -- or, excuse me, the need was determined
14 by the Commission, how did FPC envision
15 transporting the natural gas from the well fields
16 to the site?

17 A. (Mr. Niekum) At the need determination,
18 Florida Power was both a partner and a customer of
19 the SunShine Pipeline. And the method of getting
20 natural gas transportation both to Polk County and
21 to our Anclote oil-fired plant was to use the
22 SunShine Pipeline capacity.

23 Q. And is that still the case today?

24 A. (Mr. Niekum) No, it's not.

25 Q. When and how did that change?

1 A. (Mr. Niekum) There were a series of
2 circumstances as far as the SunShine Pipeline was
3 concerned. In August of 1994, Florida Power
4 dropped out of the partnership for the SunShine
5 Pipeline. Then in February 15, I believe it was,
6 in 1995, Florida Power dropped out as a customer of
7 the SunShine Pipeline. The SunShine Pipeline
8 hadn't met its targets as far as meeting -- having
9 its environmental permits, and there was some
10 question in our mind as to whether the project
11 would really be a viable supply to Polk County. So
12 FPC exercised its option at that time to drop out
13 as a customer.

14 Q. And besides the environmental
15 considerations or the inability of SunShine to meet
16 its milestone dates, were there any other reasons
17 for FPC's decision to pursue other supply options?

18 A. (Mr. Niekum) Well, there was some
19 question as to whether the Anclote gas conversion
20 made enough economic sense. The SunShine Pipeline
21 option required FPC to be an anchor customer for
22 that pipeline, which obligated Florida Power to buy
23 quite a bit of pipeline capacity on SunShine.
24 There was some doubt as to whether the gas
25 conversion at Anclote was really justified and made

1 enough economic sense. So it was an economic issue
2 as well as a reliability issue as whether the whole
3 plan as proposed was really the best option for us.

4 Q. And after Florida Power Corporation was
5 no longer a customer of the SunShine project, what
6 steps did FPC take to secure natural gas
7 transportation for the Polk facility?

8 A. (Mr. Niekum) Well, because of our
9 obligations to SunShine prior to February of '95,
10 we were obligated not to look at alternative
11 supplies. SunShine was our exclusive supplier.
12 After that we were open to opening negotiations
13 with Florida Gas Transmission Company to look at
14 what capacity could be made available for Polk.

15 Q. And would you describe what you did to
16 secure the necessary capacity.

17 A. (Mr. Niekum) Well, we really worked in
18 two steps. It's, one, we began discussions with
19 FGT to find out what they were capable of providing
20 us out of their existing system. And they at that
21 time said that they would be able to provide
22 capacity through an expansion of their system to
23 serve Polk.

24 At the same time, they were just
25 completing their Phase 3 expansion, which was to go

1 in-service, I believe, in March of '95, and there
2 were a number of shippers on FGT's system that had
3 come to realize that for whatever reason, they had
4 some excess capacity that they were going to have
5 to start paying for, and that some of them were
6 looking for ways to either sell it back to FGT or
7 find somebody else that would take the capacity
8 which was permitted under FERC Order 636.

9 So we began negotiations both with FGT,
10 who actively encouraged the secondary market with
11 these other shippers, and they gave us a list of
12 the shippers that had excess capacity or were
13 willing to discuss selling some of their capacity,
14 and we began negotiations with the larger shippers
15 that had the most capacity.

16 Q. And were you successful in obtaining the
17 requisite capacity?

18 A. (Mr. Niekum) We didn't -- we were
19 successful in the secondary market to get a
20 substantial amount of transportation capacity. We
21 haven't -- the total amount of capacity that we
22 need for Polk County we're getting through a
23 combination of the release capacity we negotiated
24 as well as participating in FGT's 1998 expansion.
25 So the end result was a mixture of both, of both

1 secondary market capacity and FGT expansion.

2 Q. Was that your first foray into the
3 secondary capacity market?

4 A. (Mr. Niekum) Well, for me personally, it
5 was. I took the job in March, and we started in
6 March, so I had never dealt in that. We did have
7 one of the buyers that came from Atlanta Gaslight
8 that knew something about it but had never made a
9 deal like that.

10 Q. How about as far as you know, Florida
11 Power Corporation had never approached the
12 secondary market to buy capacity?

13 A. (Mr. Niekum) No.

14 Q. How do you expect Polk to dispatch on
15 your system based on current information as far as
16 fuel prices?

17 A. (Mr. Niekum) We expect it to run at a
18 very high capacity factor. With the current
19 forecast of natural gas and the high efficiency of
20 the unit, it's extremely competitive to all the
21 units on our system except nuclear.

22 Q. So then it will -- in terms of economic
23 dispatch, where does it rank or where do you expect
24 it will rank?

25 A. (Mr. Niekum) It will rank very close to

1 our Crystal River 4 and 5 coal plants.

2 Q. So then is it fair to say that it will
3 operate as a base load plant?

4 A. (Mr. Niekum) Yes, it will operate as a
5 base load plant.

6 Q. And in terms of capacity factor, what do
7 you expect based on current prices?

8 A. (Mr. Niekum) Based on current prices, it
9 runs at close to a 90 percent capacity factor. But
10 it is highly sensitive to the differential of coal
11 at Crystal River, and it's extremely competitive.
12 So I've seen numbers from 75 to 90, and it only
13 matters a few pennies one way or the other of where
14 it fits.

15 Q. Are you personally responsible for
16 providing information which was included as part of
17 Florida Power Corporation's 1994, '95 and '96 --
18 and/or '96 ten-year site plan filing?

19 A. (Mr. Niekum) I worked on the -- I wasn't
20 directly involved in the 1996 one that was filed
21 this year. The 1995 filing, I was responsible for
22 some of the production of that document, and then
23 in the 1994 I was directly responsible.

24 Q. And what information did you provide for
25 those ten-year site plans?

1 A. (Mr. Niekum) Primarily the planning
2 studies that went into them that were the
3 integrated resource plans that were the
4 underpinnings of the results. The data was through
5 other departments, demand and energy forecasts,
6 fuel forecasts were obtained from other
7 departments, but put together in the integrated
8 resource plan that generated the results for the
9 ten-year site plan.

10 Q. And the fuel price forecasts for the 1995
11 plan, was that developed by your department?

12 A. (Mr. Niekum) It was developed by my
13 department, but the fuel price forecast that went
14 into the 1995 plan was developed when Norman Davis
15 was the director because that was probably done --
16 I'm not sure what the date was. It was probably
17 about August of '94. So the fuel department group
18 did it, but I wasn't the director then.

19 Q. In your position at Florida Power
20 Corporation, do you consider or view the
21 Commission's concerns regarding Florida Power
22 Corporation's planning assumptions and their
23 relative effect on the generation expansion plan?

24 A. (Mr. Niekum) I'm not quite sure I
25 understand that question.

1 Q. Do you look at the end product?

2 A. (Mr. Niekum) Of your evaluation, the
3 ten-year site plan? Yes, very much so.

4 Q. I'm going to hand you a copy of the 1994
5 ten-year site plan and ask you to turn to page 26,
6 and specifically the paragraph in the center of the
7 page that begins, would you read aloud, "To further
8 determine."

9 A. (Mr. Niekum) "To further determine the
10 sensitivity of a project's success to a change in
11 fuel forecast, a worst case scenario should be
12 evaluated. This worst case scenario is a final
13 sanity check that consists of holding current fuel
14 price differentials constant throughout the
15 projection period. This test will reveal whether a
16 project will retain overall cost effectiveness
17 under severe and continuing price drops."

18 Q. Since the Polk plant has certified, have
19 you performed or has Florida Power Corporation, to
20 your knowledge, performed a worst case scenario
21 fuel price forecast for the Polk unit?

22 A. (Mr. Niekum) I'm trying to remember if
23 this was done as an answer to an interrogatory of a
24 docket somewhere, and I'm not sure if it had. I
25 think we did studies that were close to this but

1 not exactly done this way. And I can't remember
2 for sure if we submitted what we had done or we
3 actually performed this exactly as it's described
4 here with the differentials held constant. I don't
5 specifically remember doing this study directly of
6 setting up this criteria and running this study
7 this way.

8 Q. Do you have an expectation of how the
9 Polk plant would fare based on that scenario?
10 Current information.

11 A. (Mr. Niekum) The key to this is the
12 initial differential that you start with. And with
13 our current forecast, where the differentials of
14 coal and gas are relatively small and you held
15 those differentials constant, then the Polk unit
16 would fare extremely well.

17 MR. ELIAS: Unless my friends up the road
18 have anything, I think I'm finished. Let me just
19 if I may just check with them.

20 MR. DUDLEY: We don't have anything
21 else.

22 MR. ELIAS: Okay.

23 (Brief lunch recess.)
24
25

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Prudence review to) DOCKET NO. 960409-EI
determine regulatory treatment)
of Tampa Electric Company's Polk) FILED: JUNE 14, 1996
Unit.)
_____)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that one true and correct copy of the Panel Deposition Transcript and Exhibits of Mr. Robert D. Niekum and Mr. Eric G. Major filed by the staff of the Florida Public Service Commission has been furnished by Hand Delivery, to Mr. Lee Willis, Ausley and McMullen, 227 South Calhoun Street, Tallahassee, Florida 32301, on behalf of Tampa Electric Company and that one true and correct copy has been furnished by U. S. Mail this 14th day of June, 1996, to the following:

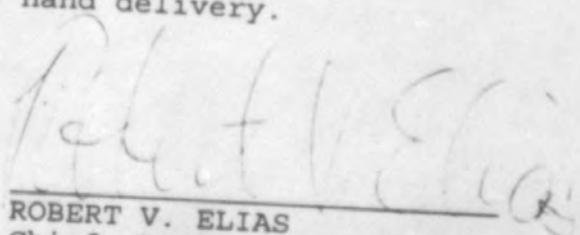
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BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

-----X
In The Matter of :
Prudence review to : DOCKET NO.: 960409-EI
determine regulatory :
treatment of Tampa : FILED: May 30, 1996
Electric Company's Polk :
Unit. :
-----X

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PANEL
DEPOSITION OF:

ROBERT D. NIEKUM
and
ERIC G. MAJOR

TAKEN BY:

The Staff of the Florida
Public Service Commission

PLACE:

Florida Power Corporation
Building A
9th Floor Conference Room
3201 34th Street South
St. Petersburg, Florida

TIME:

Commenced at 9:05 a.m.
Concluded at 4:01 p.m.

DATE:

Tuesday, June 4, 1994

REPORTED BY:

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EXAMINATION

BY MR. LONG:

Q. Good afternoon. My name is Harry Long, and I'm representing Tampa Electric this afternoon. I want to follow up with a few questions from this morning. Before we start, though, I just wanted to mention a couple of things.

I think this idea of having you testify as a panel is a really good idea, and when I ask questions, I'll just present them generally to the two of you, and you can decide who is the better person to respond. But in each instance, if the person not responding has additional information or has information that differs, I would ask you to speak up. And to the extent that I ask if you have done a study, my intention is to ask whether you personally have done it or whether Florida Power Corporation has done it, so the "you" is meant in both senses.

Can we start with what's been marked as Exhibit A, your integrated resource study dated August 1991. Can we turn first of all, to page 339.

A. (Mr. Niekum) Okay.

1 Q. Now, is the gas forecast that appears on
2 page 339 the high case forecast?

3 A. (Mr. Niekum) Yes.

4 Q. What probability did you associate with
5 this forecast?

6 A. (Mr. Niekum) I believe on the fuel
7 forecast, we associated the high and low at 25
8 percent probability and the medium forecast at
9 50 percent.

10 Q. So at 25 percent probability, would you
11 call this high forecast an unlikely forecast?

12 A. (Mr. Niekum) Well, it's less likely than
13 the midpoint forecast, but it was the idea would
14 not be to put a forecast in your plan that you
15 didn't think had some reasonable chance of
16 occurring, so we put a 25 percent probability on
17 it. So it was not as likely as the main forecast
18 or the median forecast but certainly within the
19 realm of possibility.

20 Q. Right. So you wouldn't call this an
21 unlikely forecast?

22 A. (Mr. Niekum) No.

23 Q. Now, where does your low case coal
24 forecast appear?

25 A. (Mr. Niekum) The low case coal prices is

1 on page 342.

2 Q. 342. Okay. And, again, what probability
3 did you assign to this low case forecast?

4 A. (Mr. Niekum) Again, 25 percent for the
5 high and low, so it had a 25 percent probability.

6 Q. So, again, you wouldn't refer to this as
7 an unlikely forecast given that probability?

8 A. (Mr. Niekum) No.

9 Q. Now, can I ask you to help me to figure
10 out what the differential is between your high gas
11 forecast you looked at and this low coal forecast
12 in terms of cents or dollars per MMBTU for the
13 period covered?

14 A. (Mr. Niekum) Probably to do that we'd
15 have to do it year by year, but to just take a
16 sample year would be one way to at least establish
17 some number.

18 Q. Okay. Well, could we -- I hate to put
19 you to this trouble, but for the 10 or 15 entries
20 there, could you give it to me year by year?

21 A. (Mr. Niekum) Just to make sure I do this
22 once, you're looking at the high gas price on 339
23 versus the low coal price on page 342; is that
24 right?

25 Q. That's right.

1 A. (Mr. Niekum) I've done 10 years from 1999
2 through 2008, which was kind of a range of a
3 ten-year study.

4 Q. Can you tell me what your results are?
5 What is the differential?

6 A. (Mr. Niekum) The differential is about
7 \$5.78 in 1999 to about \$10.80 in 2008.

8 Q. Now, based on this calculation, the
9 differential isn't constant through that period, is
10 it?

11 A. (Mr. Niekum) No. It expands.

12 Q. I want to ask you to do one more
13 comparison, but before we do that, let me ask you a
14 question about pet coke. Is it your sense that the
15 pet coke prices would have been higher or lower
16 than your coal prices?

17 A. (Mr. Niekum) Pet coke is more than likely
18 to be lower than coal prices.

19 Q. And to the extent that it's lower and you
20 have made that comparison, the differential that
21 you just calculated would have been greater by
22 whatever the difference would be between the pet
23 coke price and the coal price?

24 A. (Mr. Niekum) Yes.

25 Q. Now, let me ask you to do one more

1 comparison, and then we'll finish with
2 calculations. I'd like you to look at page 341.
3 Now, does that contain your base coal price
4 forecast?

5 A. (Mr. Niekum) Yes.

6 Q. And is the base gas price forecast on
7 page 337?

8 A. (Mr. Niekum) Yes.

9 Q. Would you do that same comparison using
10 the base case. Just go from 2004 to 2010, just so
11 we get a flavor for that.

12 A. (Mr. Niekum) Looking at 2004 through
13 2009, the differentials went from about \$3.58 to
14 \$4.59.

15 Q. Again, not a constant relationship?

16 A. (Mr. Niekum) No.

17 Q. Now, what probability did you associate
18 with these base case forecasts?

19 A. (Mr. Niekum) Approximately 50 cents -- or
20 50 percent probability.

21 Q. So are these the most probable fuel price
22 forecasts of the forecasts that you presented?

23 A. (Mr. Niekum) Yes.

24 Q. Did you prepare any cost effectiveness
25 analysis or any economic analysis of the IGCC

1 alternative?

2 A. (Mr. Niekum) Yes. We did it in a
3 comparative basis with the other alternatives. At
4 the time the purpose of the study was to discern
5 which alternatives had the lowest cost to our
6 system over the planning horizon. So the answer to
7 your question is that we didn't prepare it in
8 isolation. It was done on a comparative basis with
9 the other alternatives. So in a straight sense of
10 just simply looking at IGC in isolation, no, we
11 didn't do that. We did do it as a comparative
12 basis.

13 Q. I see. Is that study included in
14 Exhibit A?

15 A. (Mr. Niekum) Yes.

16 Q. Can you show me where that is?

17 A. (Mr. Niekum) Well, the actual study isn't
18 in this document. There was background document of
19 all the computer runs and PROSCREEN analysis that
20 was done, but the economic and risk analysis
21 section describes the results of those studies,
22 which is the comparison of the cumulative present
23 worth revenue requirements of the alternatives as
24 well as the risk assessment of a likelihood of
25 forecast probabilities, what the results of those

1 probabilities would be, the riskiness of the
2 alternatives compared to the selected alternative.

3 Q. Now, if you had assumed pet coke as a
4 fuel stock, would that have had some effect on your
5 analysis?

6 A. (Mr. Niekum) It would have lowered the
7 fuel stock on any of the alternatives either the
8 pulverized coal or the IGCC plants that could have
9 used it.

10 Q. In your analysis did you run a scenario
11 where you assumed that the gas pipeline which you
12 would need to deliver your fuel supply would be
13 delayed?

14 A. (Mr. Niekum) In the course of the initial
15 analysis, the initial analysis for the need
16 determination, that wasn't part of that. It was
17 assumed we had -- we had gone in eight years prior
18 to the construction of the project, and we weren't
19 looking at delays at that time. Later on, I think,
20 in one of the later exhibits, as we continued to
21 look at Polk County, sensitivities of what we would
22 do if the pipeline were delayed or what the impacts
23 on the delay of the pipeline was considered as a
24 sensitivity to a study.

25 Q. Are those sensitivities included in

1 Exhibit A?

2 A. (Mr. Niekum) On pipeline delay?

3 Q. Yes.

4 A. (Mr. Niekum) No.

5 Q. What delay did you assume in those
6 sensitivity studies?

7 A. (Mr. Niekum) I believe, again, this
8 was the -- I can't remember the exhibit number, but
9 it was looking at one-year delay, I believe.

10 Q. So you didn't look at a delay of longer
11 than one year in your sensitivity analysis?

12 A. (Mr. Niekum) In that particular study,
13 no.

14 Q. And what was the result with the one-year
15 delay? How did that impact your project?

16 A. (Mr. Niekum) It looks like in this study
17 the delay resulted in a cost increase of about
18 \$20 million in fuel costs.

19 Q. Now, that's -- we marked that document as
20 an exhibit. What page of Exhibit B are you looking
21 at?

22 A. (Mr. Niekum) That's -- it's not really
23 marked page. It's in Attachment No. VIII, and it's
24 the third page into the attachment, but it has page
25 No. 1 on it because it was a report that was

1 included.

2 Q. Okay. Could I borrow Exhibit B for a
3 second? Thank you. Just so that we're clear, at
4 this point your plans called for building how many
5 megawatts at the Polk site?

6 A. (Mr. Niekum) Okay. We're talking two
7 time frames here. One is on Exhibit A it was in
8 1991. Exhibit B was in '94. When you say at this
9 time --

10 Q. Your current plan.

11 A. (Mr. Major) 470 for the initial block of
12 construction.

13 Q. Okay. And the in-service date is
14 projected to be what?

15 A. (Mr. Major) November of '98.

16 Q. November of '98. And I believe you
17 indicated earlier that that's a little bit
18 different than the configuration that the
19 Commission outlined in the need hearing decision?

20 A. (Mr. Major) That's correct.

21 Q. And just to cover that, what was the
22 configuration that the Commission addressed in its
23 decision?

24 A. (Mr. Major) 230 in '98, November of '98,
25 235 in November of '98, and 235 in November of

1 '99.

2 Q. Okay. And you're bringing on 470 at once
3 in '98?

4 A. (Mr. Major) Yeah.

5 Q. Do you have a copy of the need hearing
6 decision, by any chance?

7 A. (Mr. Major) Not with us.

8 Q. Let me share this with you. I'm looking
9 at pages 36 and 37 of the order from the need
10 hearing. It will be simpler if I just share this
11 with you. If you could look at Paragraph 144 on
12 page 36. Now, there you talk about the current
13 site specific cost estimate of \$566 per kilowatt in
14 '91 dollars. What number of installed megawatts is
15 that number based on?

16 A. (Mr. Major) Do we have all of my
17 testimony in there? That was more than likely the
18 40-megawatt option.

19 Q. I see. If you know, what would the cost
20 per kilowatt be for the first unit, the
21 235-megawatt unit that the Commission envisioned to
22 go in-service for November of '98?

23 A. (Mr. Major) Can you total some numbers?
24 199, 85, 26, 2. Divide that by 235. 1,300? It
25 would have been somewhere around \$1,300 per KW.

1 Q. Okay. Thank you. I'd like to go back
2 and talk a little bit about the site selection
3 process that you went through for your Polk plant.
4 At the time you determined that you would need to
5 find a site to build a plant -- and maybe we should
6 pin a date on that. When was that that you first
7 decided that you had to locate a site for the plant
8 that you're now building?

9 A. (Mr. Major) The site selection activity
10 started early in '98.

11 A. (Mr. Niekum) '88.

12 A. (Mr. Major) Yeah, '88. And I'm not sure
13 there's an exact date. I think it --

14 Q. Just ballpark is fine.

15 A. (Mr. Major) Early '88.

16 Q. Now, that was prior to your forming your
17 advisory group?

18 A. (Mr. Major) Yes.

19 Q. Now, at that time before you formed the
20 advisory group, what potential sites did you have
21 in mind, places that you wanted to investigate?

22 A. (Mr. Major) I think at that time we
23 didn't -- we didn't have any specific sites in
24 mind, although in the mid '80s we had -- well, it
25 goes back prior to the mid '80s. In the late '70s,

1 early '80s, we had a project called our mid '80s
2 project where we were going to develop pulverized
3 coal units up in the Panhandle near Port St. Joe.
4 So that was a site that we had some data on, and
5 that was one of the alternatives that was going to
6 be thrown in with the entire study in terms of
7 finding a site.

8 Q. Now, in the period prior to '88, you
9 mentioned this had been a site that you had in mind
10 as a potential site anyway. Why did you feel up to
11 that point that it was a potential site? What was
12 attractive about the site to FPC?

13 A. (Mr. Major) We had some prior knowledge
14 on that site because we had done some environmental
15 studies. I think we had checked out the
16 availability. It was on a waterway where we could
17 get fuel supplies in to it, I think, and had
18 cooling water availability. So those were the
19 primary factors, I think, that favored that site.

20 Q. Now, what led you to form your advisory
21 group?

22 A. (Mr. Major) I wasn't involved in the
23 decision making, but from my recollections and
24 discussions, it was to get members of the public
25 involved in the process so that, first off, we get

1 a better product and, secondly, we get better
2 buy-in by members of the public once that the
3 recommendations were made on where to locate.

4 Q. Now, was the advisory group set up to
5 operate autonomously from FPC? In other words,
6 were they given a charter to go out and come back
7 to you with specific recommendations and order of
8 priority for sites?

9 A. (Mr. Major) No. They were -- they were
10 formed to work jointly with FPC in an advisory
11 capacity. They were not viewed as being the
12 decision makers but being strictly in an advisory
13 capacity.

14 Q. Now, do you recall roughly when the
15 advisory group was formed, when they first met?

16 A. (Mr. Major) I'd have to dig out records.
17 It was sometime in '98, but in terms of how far
18 into the process, I'd have to look into that.

19 Q. Did you mean '88?

20 A. (Mr. Major) '88, yeah.

21 Q. I do that all the time. Now, when the
22 committee was formed, were they given a specific
23 charter? I mean, what -- to the extent you're
24 aware, what instructions were they given as to how
25 to proceed?

1 A. (Mr. Major) I can't answer that question
2 because I wasn't involved. I know that they
3 participated in the defining and agreeing upon some
4 key parameters that would be utilized in the
5 evaluation process and assigning weights to those
6 parameters, such as environmental impacts,
7 economics, the land use impacts.

8 Q. Okay. I think Exhibit B talks a little
9 bit about the selection criteria --

10 A. (Mr. Major) Yes.

11 Q. -- and discussion process. In the course
12 of the committee's work and your work, did you
13 narrow down the universe of potential sites to a
14 manageable group ultimately?

15 A. (Mr. Major) Yes. I think initially some
16 exclusion zones were identified, such as proximity
17 to airports, wetland areas, endangered habitat
18 areas. And then from there I think there were like
19 50 or 60 specific sites identified. And then that
20 got narrowed down, I think, into the high teens or
21 early twenties, and then finally got narrowed down
22 to about six locations when it came down to the
23 very end of the process.

24 Q. That Port St. Joe site that you mentioned
25 at the outset, was that one of the six that

1 ultimately emerged?

2 A. (Mr. Major) I don't believe the Port St.
3 Joe site made the final cut. I don't believe there
4 was any site along the coast that made the final
5 cut in the selection process.

6 Q. Do you know why that was?

7 A. (Mr. Major) I believe that the coastal
8 impacts, impact on sea grasses, and visual impacts,
9 and those were the primary concerns.

10 Q. In terms of this Port St. Joe site in
11 particular, do you recall any factors that would
12 have weighed against it?

13 A. (Mr. Major) From the -- from the
14 environmental and cost aspects, transmission
15 impacted that site pretty significantly because of
16 the distances the transmission would have to be
17 brought to the load centers. And then associated
18 with the transmission construction there were
19 significant environmental impacts in terms of
20 wetland impacts and land use impacts.

21 Q. If you know, were any detailed
22 engineering studies done on this Port St. Joe site
23 to get a more definitive handle on what the
24 mitigation costs might be, what the site
25 preparation costs might be?

1 A. (Mr. Major) There were -- there were some
2 cost estimates that were done as part of the mid
3 '80s project, and I'm not sure if those numbers
4 were utilized during the site selection of the Polk
5 County site or not. I just can't answer that
6 without checking through the reports.

7 Q. In terms of the six sites that you ended
8 up with toward the end of the process, can you tell
9 me how -- first of all, how the advisory group
10 evaluated these sites, on what basis, and then
11 could you tell me on what basis Florida Power
12 evaluated these sites?

13 A. (Mr. Major) I believe that the six sites
14 were -- they were evaluated on the parameters that
15 were identified by the Florida Power team and the
16 environmental advisory committee. I think when it
17 got to the final six, the environmental impact
18 favored the Polk County site as, I believe, did the
19 costing, because of the close proximity to our load
20 centers and the minimal transmission requirements.

21 And I think there was -- there was
22 general concurrence among both the environmental
23 advisory group and the Florida Power folks that
24 that appeared to be the favored site. From the
25 environmental group primarily because the

1 properties had already been disturbed through
2 previous mining efforts, and that that site could
3 potentially be improved upon by some of the site
4 development activities that would result from the
5 plant.

6 Q. To what extent did the advisory committee
7 base its recommendations on the alternative land
8 costs or alternative reclamation mitigation costs?

9 A. (Mr. Major) I think the environmental
10 advisory group focused principally on the
11 environmental impacts. I think costs, in their
12 mind, were secondary.

13 Q. Now, from a site development, site
14 preparation, mitigation point of view, was the Polk
15 site that you ultimately chose the least expensive
16 of the sites that you were considering?

17 A. (Mr. Major) I believe that from the site
18 development perspective, it was not the least
19 expensive, but when you factored in the
20 transmission requirements to get the generation out
21 of the site, the economics favored the Polk site.

22 Q. In terms of the engineering challenges
23 that each site would pose in building the plant
24 that you had in mind, did the Polk site pose the
25 fewest engineering challenges?

1 A. (Mr. Major) It would have -- from the
2 site development perspective, it posed the greatest
3 challenges of all the sites.

4 Q. And why is that? I mean, what were you
5 looking at that led you to that conclusion?

6 A. (Mr. Major) Well, because the site had
7 been totally disturbed through phosphate mining,
8 and there were significant development efforts in
9 order to make a parcel suitable to build the power
10 block on, to build the plants on. There were some
11 opportunities in terms of using the clay settling
12 areas as cooling ponds, but it was a -- it was
13 probably the greatest challenge of all the other
14 sites in terms of the site development.

15 Q. Now, did the advisory committee give you
16 any kind of final formal report containing their
17 recommendations as a group?

18 A. (Mr. Major) I don't know that there was a
19 final report issued. I can't be positive, but I
20 don't recall a final formal report that was
21 issued. In fact, toward the end of the selection
22 process, there were concerns by one of the state
23 agencies, I think it was the Bureau of Mines, which
24 did not fall within DEP at the time, but they were
25 responsible for reclamation, and there were some

1 concerns about the replenishment of waters to
2 MuCullough Creek, and the Polk site was located
3 right at the headwaters of MuCullough Creek. So we
4 had several meetings with the agencies to alleviate
5 their concerns about the MuCullough Creek
6 situation.

7 Q. Were the conclusions or, for that matter,
8 the deliberations of the advisory committee
9 routinely made public?

10 A. (Mr. Major) There was some information
11 that was shared with the media, but I don't believe
12 there was a formal process established where all
13 that was made public.

14 Q. Did you publicize your choice of the Polk
15 site at the time that you selected it?

16 A. (Mr. Major) No.

17 Q. Now, again, can you give me a ballpark
18 idea when did you decide that the Polk site was
19 where you wanted to be?

20 A. (Mr. Major) In around the -- it was
21 October of '88 -- October of '89. And then we had
22 some discussions with the Bureau of Mines
23 concerning -- which was around Thanksgiving of '89,
24 and then we started developing our contracts with
25 consultants or getting involved in the

1 environmental studies and putting together the need
2 in all the information regarding the site.

3 Q. Now, how soon after you decided that the
4 Polk site was it did you start to approach
5 landowners?

6 A. (Mr. Major) I believe that that happened
7 around the first quarter of 1990.

8 Q. So fairly soon after you made the
9 decision that you wanted the Polk site?

10 A. (Mr. Major) Yeah. Because there had been
11 some previous discussions with the property owners,
12 I think specifically IMC and Estech, to determine
13 that there wasn't -- that, first off, those
14 properties wouldn't be required for any mine
15 expansion plans or plans they had into the future.
16 And there had been willingness expressed by the
17 parties to work with us to settle those properties.

18 So once the decision was made that Polk
19 was the preferred site, we -- we did approach the
20 property owners concerning our intentions and
21 confirming that those properties would still be
22 available. At that point in time, though, I
23 believe we did carry a backup alternative, which
24 was in Hardee, about 20 miles to the south. So we
25 did -- did indicate to them that there was a backup

1 that was also being considered.

2 Q. Now, you discussed earlier the sellers
3 that you approached. Bear with me for just one
4 second. Before we move to that topic, I did want
5 to ask a couple more questions about the advisory
6 committee. Do you have any records or files that
7 might have been kept by the advisory committee?

8 A. (Mr. Major) Kept --

9 Q. By the corporation.

10 A. (Mr. Major) Yeah. We've got -- I'm sure
11 that we've got records that detailed the studies
12 and analyses that were done during the route
13 selection there in our archives somewhere.

14 Q. Once you decided on the Polk site, how
15 did you decide how many acres in total you would
16 need to acquire for the project?

17 A. (Mr. Major) I believe that there were --
18 there were some preliminary development plans that
19 were laid out during the site selection process in
20 terms of tentatively identifying some cooling pond
21 areas and where the power block would be located.

22 And then when we brought our
23 environmental consultants on board and we brought
24 Black & Veatch on board prior to the need
25 determination to support some of the -- some of the

1 environmental studies, I think jointly with them we
2 reviewed what had been done during site selection
3 and in pretty conceptual terms identified the
4 general requirements of the site and where the
5 property boundaries were, where existing dams were.
6 So a lot of features were already evident from how
7 the land was utilized by the mining companies and
8 that contribute also to defining the site
9 boundaries.

10 Q. So you ultimately purchased 8,200 acres?

11 A. (Mr. Major) That's correct.

12 Q. So at this point in the process, you had
13 defined the need for 8,200 acres?

14 A. (Mr. Major) It was in the -- I think it
15 probably would have been -- it wasn't that precise,
16 but roughly 8,000, you know, ballpark of that
17 size.

18 Q. And how much of that 8,000 acres did you
19 think you might need for reclamation mitigation and
20 environmental mitigation?

21 A. (Mr. Major) Going -- going into the
22 process, I'm not sure we had a real good feel on
23 what the mitigation requirements specifically were
24 going to be with the agencies. I think we had --
25 we had some indications of the cooling pond size.

1 I believe going into the process initially we were
2 looking at pulverized coal units. So we had some
3 indication of how much ash storage would ultimately
4 be required. And that -- I think those were the
5 key drivers on establishing the overall site size
6 was the cooling pond requirements and the storage
7 requirements for ash.

8 Q. I believe you indicated that you
9 approached IMC, is it Estech?

10 A. (Mr. Major) Yes.

11 Q. And Agrichem. Those are the three
12 sellers of property?

13 A. (Mr. Major) That's correct.

14 Q. And you said that IMC had 4,700 acres
15 available, Estech had 2,500 acres, and Agrichem had
16 70 to 100 acres.

17 A. (Mr. Major) Well, those were the -- those
18 were the size parcels that were purchased.

19 Q. Were purchased?

20 A. (Mr. Major) That were purchased. IMC
21 had significantly larger holdings available, as did
22 U.S. Agrichem, but that was the final size of the
23 parcels that were purchased.

24 Q. So you purchased three parcels?

25 A. (Mr. Major) Yeah. Well, and we purchased

1 two and the one that's still pending that we have
2 an option on that we have until '98 to make a final
3 decision.

4 Q. Now, which parcel is that?

5 A. (Mr. Major) That's the 70 acres where I
6 defined the notch area that extended into our
7 property boundary.

8 Q. Is that the Agrichem property?

9 A. (Mr. Major) Yes.

10 Q. Okay. Help me to understand how this
11 adds up. If 4,700 acres from IMC and 2,500 acres
12 from Estech, where is the balance of the --

13 A. (Mr. Major) I think, Harry, my math may
14 be wrong. Maybe the 47 should be -- 2,500 from
15 Estech. That's definite. IMC -- IMC has got to be
16 5,700 acres.

17 Q. Okay.

18 A. (Mr. Major) So the 4,700 was an error.

19 Q. Now, the actual power block, which parcel
20 is that going to be located on?

21 A. (Mr. Major) It will be located on the
22 Estech properties.

23 Q. Now, you indicated that you started
24 talking in earnest with the sellers in the first
25 quarter of '90; is that right?

1 A. (Mr. Major) In the first quarter of '90,
2 I think we had the initial -- that was -- those
3 were the initial discussions with the mining
4 companies following site selection to confirm that
5 those properties were still available and they had
6 no need for in their long-term plans and agreed
7 that we would then over the course of the next few
8 months be getting with them for some serious
9 discussions concerning purchase options.

10 The -- I am not positive. I'd have to
11 research our records. But I believe that we did
12 not get into serious negotiations on the options
13 until after the need hearings were conducted.
14 Because I believe one of the questions was raised
15 on what if the owners do not agree to come to
16 terms, and I think my testimony was, well, we had
17 the right to eminent domain in a situation like
18 that.

19 Q. Now, at the time of the need hearing, I
20 think you indicated that you filed in August of
21 '91?

22 A. (Mr. Major) Yes.

23 A. (Mr. Niekum) Yes.

24 Q. And the hearings were late '91 and the
25 decision followed that. At the time of your filing

1 in August of '91, what steps had you taken to
2 secure the property, these three parcels?

3 A. (Mr. Major) I believe that there were no
4 steps taken beyond discussions with the mining
5 companies to assure that they had an interest in
6 selling. And I need to confirm that, but I am
7 positive that we didn't get into detailed
8 negotiations for land options until after the need
9 hearings.

10 Q. Okay. So no options, no entitlement,
11 no -- no way of securing the property at that time
12 prior to the filing?

13 A. (Mr. Major) I believe that is correct.

14 Q. How soon after the -- let me back up for
15 a second. Had you discussed pricing terms with the
16 sellers prior to the need hearing?

17 A. (Mr. Major) I don't believe so.

18 Q. Now, you negotiated options to purchase
19 after the need hearing?

20 A. (Mr. Major) Yes.

21 Q. Do you remember approximately when?

22 A. (Mr. Major) I will have to look up our
23 records to establish that in terms of when that
24 started and when those options were executed. Can
25 I look at that exhibit, whether that may have it.

1 I'll have to research our files to get those.

2 Q. Was your agreement to purchase these
3 parcels conditioned on the occurrence of any
4 particular events?

5 A. (Mr. Major) Once we -- yeah, the option
6 agreements did condition the purchase. It was
7 conditioned on us receiving site certification and
8 all necessary permits to construct the units, as
9 well as conditioned on -- I know that in the first
10 quarter of 1990 when we made our initial contacts
11 with the property owners to confirm that they were
12 willing to sell the properties, and then during the
13 time that studies were undertaken in order to
14 evaluate the conditions of the site, I believe we
15 had some side agreements with the mining companies
16 that we would be allowed on their properties.

17 But there was no cost involved, but that
18 was just a condition for going forward with the
19 sites to get permission to be on their properties
20 and do studies and analyses. But once the option
21 agreements were executed in terms of closing on the
22 site, that was conditioned on us receiving all
23 permits and site certification.

24 Q. I'd like to ask you to take a look again
25 at the Commission's decision in your need hearing,

1 specifically Paragraph 148 on page 37.

2 A. (Mr. Major) Okay.

3 Q. Now, as I understand the paragraph, the
4 Commission noted that your site development cost at
5 the time was going to be \$64 million in '91
6 dollars?

7 A. (Mr. Major) Yes.

8 Q. Now, on Exhibit E, your current estimate
9 for land and site development is \$83,000,755?

10 A. (Mr. Major) 755,000, yes.

11 Q. I'm sorry. Can you help me understand
12 the difference between those two numbers?

13 A. (Mr. Major) The difference between the 83
14 and the 64?

15 Q. Yes.

16 A. (Mr. Major) Escalation is one difference
17 where the 64 million was in '91 dollars, and I'm
18 not sure whether that had AFUDC included. I
19 believe that the difference is that the 862 million
20 that's referred to for the total installed cost
21 included -- that was for the four units and
22 included AFUDC and escalation. The 64 million, I
23 believe, was site development costs in terms of '91
24 dollars, did not include escalation and I believe
25 did not include AFUDC.

1 Q. So you think the difference is just
2 escalation and AFUDC?

3 A. (Mr. Major) I believe so.

4 Q. Now, again, the \$64 million number --

5 A. (Mr. Major) Yes.

6 Q. -- was that reflective of the land and
7 site development costs for the build-out to 940
8 megawatts, which is what you were requesting?

9 A. (Mr. Major) Yes, it was.

10 Q. And the \$83 million number on Exhibit E,
11 is that also reflective of your current estimate of
12 build-out for 940 megawatts?

13 A. (Mr. Major) Well, it is reflective of the
14 build-out necessary to accommodate the initial
15 block of units, the 470. But because of the site
16 as we purchased it, the location of the dams around
17 the clay settling ponds, the area that will
18 require -- that is required to be developed for the
19 cooling pond was defined by those existing dams,
20 and so the site lent itself to doing a certain
21 scope of work independent of whether that was for
22 470 or 940.

23 So in actuality, we did what was
24 necessary for the 470, but in reality it provided
25 us, in terms of cooling pond capacity, for the

1 1,500 megawatts, and in terms of the power block
2 where the units will be located, since we had to
3 gather all of the fill out of one area where the
4 clays had not been deposited, in actuality the
5 power block is there for most of the ultimate
6 development of the site short of the area where the
7 coal pile and coal handling facilities are going to
8 be located.

9 Q. In terms of is your next increment 940 or
10 is it 1,500 megawatts in terms of what you would
11 construct there?

12 A. (Mr. Major) Well, that depends on the
13 plan that we would utilize to make our expansion
14 decision on. Right now it would likely be another
15 470 or nominal 500-megawatt expansion.

16 Q. Well, what additional site preparation or
17 land costs or reclamation costs would you incur for
18 that next stage of build-out to 1,000, 1,200
19 megawatts?

20 A. (Mr. Major) There would be -- there would
21 be some mitigation along the buffer areas that --
22 that will not be booked with the original unit, and
23 I think those costs are estimated to be somewhere
24 around two to three million dollars. I believe
25 that's about the extent of it.

1 Q. So there are no other site preparation
2 costs that you would incur to build out to that
3 next level to 1,200 megawatts?

4 A. (Mr. Major) There will be -- there will
5 be some ongoing clay consolidation in two areas in
6 the northern extremes of the property that may
7 involve another couple of million dollars, but
8 that's it.

9 Q. Now, you mentioned earlier that the site
10 has been certified ultimately for 3,000 megawatts?

11 A. (Mr. Major) It's been -- well, what we
12 have done is we have demonstrated the ultimate
13 capabilities of the site for 3,000 megawatts. For
14 any incremental additions beyond the first 470,
15 we'll be required to go back for a supplemental
16 certification, which, in our minds, can reduce the
17 time requirements for securing approval by maybe
18 half the amount of time required.

19 Q. Now, what additional costs, site
20 preparation, reclamation mitigation costs would you
21 expect to incur in connection with the build-out to
22 the ultimate capacity for the site, 3,000
23 megawatts?

24 A. (Mr. Major) Beyond -- beyond the 1,500
25 megawatts, the cooling pond would require

1 expansion, which would -- it would about triple the
2 size of the cooling pond. And there will be some
3 transmission requirements associated with expansion
4 beyond 1,500 megawatts. Those are the primary
5 items.

6 Q. What costs would you associate with that
7 work?

8 A. (Mr. Major) I'd have to give you just
9 ballpark numbers. In terms of the cooling pond
10 expansion, the bulk of that work beyond the several
11 million that I've already mentioned for
12 consolidating the clay ponds would be the
13 preparation of the dams, putting soil cement or
14 something similar on the dams. In ballpark
15 estimates, that could be four to five million
16 dollars.

17 The transmission, I think we're
18 projecting 25 mile, 230 line, maybe three to four
19 million dollars of transmission related, unless
20 there were transmission requirements apart from the
21 plant that would result in additional lines being
22 built.

23 Q. Now, does that -- in that scenario, the
24 3,000 megawatt build-out, does that assume that you
25 will put in IGCC units? Is that what those

1 estimates are based on?

2 A. (Mr. Major) Well, when we did the
3 certification, in order to pick what, in our minds,
4 would have been the worst case environmental
5 situation in terms of air emissions, water
6 consumption, construction impacts, we utilized the
7 IGC as being our worst case in terms of
8 environmental impacts. That was also supported
9 that at the time the need was filed, we envisioned
10 this site satisfying our native load requirements
11 over a 25-year period.

12 And it was consistent with thoughts early
13 on that gas prices could escalate faster than coal
14 and that differential would expand and make natural
15 gas noneconomic. So the site capabilities were
16 demonstrated on IGCC, but we didn't have a
17 definitive expansion plan that supported it. It
18 just made sense at the time to consider that it
19 would provide for alternative fuels.

20 Q. But just so I understand, the additional
21 build-out costs that we were discussing just now,
22 building out to 3,000 megawatts, when you were
23 estimating those amounts, did you have in mind that
24 the plant additions would be IGCC units?

25 A. (Mr. Major) Yes. Because our cooling

1 pond, if we stayed with natural gas as a fuel,
2 could -- we could probably reduce some of those
3 expansions. Transmission, it wouldn't matter.

4 Q. But if you didn't build an IGCC unit in
5 that build-out to 3,000 megawatts, are you saying
6 you'd need different cooling pond requirements?

7 A. (Mr. Major) The cooling ponds could --
8 the magnitude of expansion could be somewhat less
9 than going with IGCC.

10 Q. Going back to Exhibit E, excluding the
11 additional build-out amounts that we just discussed
12 going up to 1,500 megawatts and ultimately 3,000
13 megawatts, your total site development estimate at
14 this time is \$111,326,000?

15 A. (Mr. Major) That is correct, with the
16 exception of buffer areas, the mitigation on the
17 buffer areas, which would contribute about
18 \$2 million more.

19 Q. Another \$2 million?

20 A. (Mr. Major) Yes.

21 Q. Now, the breakdown that you have given us
22 on Exhibit E is that of that total of 111, or the
23 total would be 112 or 113 as you just corrected it,
24 83.7 million of that is land cost and site
25 development, 25.3 million you attribute to site

1 certification and licensing, and 2.2 million,
2 roughly, you attribute to site selection?

3 A. (Mr. Major) Yes.

4 Q. Let's take the site selection category
5 first. Can you tell me what the \$2.2 million was
6 spent on?

7 A. (Mr. Major) Yeah. It was spent on all --
8 the site selection process extended over about a
9 two-year period. So that represents all staffing,
10 Florida Power personnel participating in the site
11 selection. We had retained Woodward-Clyde and
12 Associates as a consultant assisting us in the site
13 selections. Included some mapping aerial surveys
14 used in evaluating all potential locations around
15 the state. I'm not sure, it may have included some
16 of the expenses for the environmental advisory
17 group. And I believe Black & Veatch provided some
18 assistance to Woodward-Clyde in some conceptual
19 engineering studies, and that would -- and some
20 AFUDC costs.

21 Q. Now, what about the 25.3 million for site
22 certification and licensing. What was that money
23 spent on?

24 A. (Mr. Major) That was for the four years
25 starting in early -- starting in the beginning of

1 1990 through '94 -- through ninety -- actually, it
2 was through the first quarter of '94, and that
3 represented the preparation for the need, need
4 hearings, the need -- going through the need
5 hearings, all of the consulting and modeling that
6 was required to perform the -- put together the
7 site certification application, Black & Veatch's
8 support of the environmental consultant's air
9 modeling, attorney's fees, Florida Power staff
10 fees.

11 Q. Permitting fees, is that included in
12 here?

13 A. (Mr. Major) Yes. Well, yeah, the
14 application fee for site certification, all those,
15 yes, they were in there.

16 Q. Any option payments?

17 A. (Mr. Major) No. Those would have been
18 considered part of the land acquisition costs, and
19 they are shown in land and site development.

20 Q. Now, of the \$83.7 million in the land and
21 site development category, how much of that
22 represents the actual cost of the land which you
23 purchased?

24 A. (Mr. Major) It is right at \$9 million, I
25 believe. Yeah, \$9,043,000.

1 Q. So approximately 74 million of that
2 83.7 million would have been spent on site
3 development activities?

4 A. (Mr. Major) Yes. Well, okay. The land
5 was \$9,043,000. There was also the payment that I
6 had mentioned to IMC for relocating their clay
7 slurry line. That was another -- okay. That's --
8 yeah, that was part of that 83. That's not part of
9 the \$.

10 Q. Right. Okay. So then actual site
11 development costs would be estimated at 70, roughly
12 70 million?

13 A. (Mr. Major) Yeah.

14 Q. Okay.

15 (Mr. Wieland entered the deposition
16 room.)

17 (Discussion held off the record.)

18 BY MR. LONG:

19 Q. So looking at Exhibit E, roughly 70
20 million out of the 83.7 million is attributable to
21 site development. Now, when you talk about site
22 development, does that category include any --
23 aside from the 3.9 million that you spent to move
24 the clay pipeline, does that number include all of
25 the environmental mitigation, all of the site

1 reclamation work in addition to the earth moving,
2 the actual construction?

3 A. (Mr. Major) Yes, as well as significant
4 consulting fees and developing the site development
5 designs, the earth work drawings, and submittals
6 that were made through the agencies in terms of the
7 defining the design work for the site development.

8 Q. Now, if I understood --

9 A. (Mr. Major) As well -- excuse me. As
10 well as the pipeline connecting the cooling pond to
11 the city of Bartow's sewage treatment plant.

12 Q. Now, if I understood what you said
13 earlier, you don't necessarily break down those
14 dollars between reclamation costs and environmental
15 mitigation costs, do you?

16 A. (Mr. Major) No.

17 Q. Before we go ahead, I want to ask you a
18 question about Exhibit B. It is under Attachment
19 IV. There are no page numbers, but it's the first
20 page after the Attachment IV tab in Exhibit B.
21 Now, there's a category -- this is a '93
22 projection, I guess?

23 A. (Mr. Major) Uh-huh.

24 Q. There's a category for land, reclamation
25 and site work. Now, that shows a number for land

1 cost of roughly \$9 million, a little bit under,
2 which is the amount that you identified in Exhibit
3 E in that \$83.7 million?

4 A. (Mr. Major) Right.

5 Q. Now, the total for that category comes
6 out to be something over \$55 million?

7 A. (Mr. Major) Yes.

8 Q. Now, does that compare with the
9 \$70 million number that we just extracted from
10 Exhibit E?

11 A. (Mr. Major) I believe that these are
12 costs without AFUDC included.

13 Q. Okay. Is that -- is that the only
14 difference?

15 A. (Mr. Major) Should be the only
16 difference. Other than -- well, that plus being
17 two years later into the process and fine-tuning
18 these.

19 Q. Well, that's what I wanted to try to
20 figure out. Aside from AFUDC, have any of the cost
21 estimates there in that breakdown changed that
22 you're aware of?

23 A. (Mr. Major) The land, the pipeline cost
24 has not changed. The reclamation was fine-tuned
25 when we received bids from the contractors, so that

1 would have changed some. I think we're still
2 carrying the same estimate on the corps of
3 engineers, which is the mitigation. There's an
4 entry that shows piles, and that likely would now
5 be carried in the -- could be carried in the plant
6 costs, I believe, because that will be done under
7 the scope of the plant construction or may not be
8 required. The pipeline essentially the same. I
9 think our inspectors and consultants is higher than
10 what was projected back at that time.

11 Q. Is there any contingency amount in the
12 \$70 million number that we extracted from
13 Exhibit E?

14 A. (Mr. Major) No. Because that work, as
15 far as we're concerned, in August that will
16 essentially be complete and we've got a fixed price
17 contract with the contractor.

18 Q. What is the approximate acreage covered
19 by the power block?

20 A. (Mr. Major) For the initial unit?

21 Q. Yes.

22 A. (Mr. Major) Approximate, I would say 50
23 acres or so. Not -- well, for the power block,
24 roughly 50 acres.

25 Q. Okay.

1 A. (Mr. Major) Then the cooling pond is
2 roughly 750 acres.

3 Q. Are there any other facilities that you
4 would include under the heading of the footprint of
5 the plant?

6 A. (Mr. Major) Well, the trans -- I would
7 not include it under the footprint of the plant,
8 but all the -- the majority of the transmission
9 facilities will be contained on the plant property
10 that go between Barcola and to the plant site,
11 which is about three, two and a half, three miles,
12 and then several -- at least a mile or several
13 miles of transmission that goes to the south to our
14 Fort Meade substation would comprise part of that
15 plant property, as well as the switch yard for the
16 substation serving the plant.

17 Q. To what extent is the cost for
18 transmission or for the switch yard included in the
19 \$70 million site development estimate that we're
20 talking about?

21 A. (Mr. Major) That is a separate line
22 item. It's not included in the land and site
23 development.

24 Q. Is that included as part of the
25 construction cost of the plant as opposed to site

1 development?

2 A. (Mr. Major) Yes.

3 Q. Looking at the power block acreage and --

4 A. (Mr. Major) Let me qualify that in terms
5 of Exhibit C, there's a separate entry that says
6 transmission and substation plant, and that total
7 rolls into the total cost for the project.

8 Q. So it's not a part of the plant cost,
9 it's a separate cost item?

10 A. (Mr. Major) Well, it's part of the 580
11 per KW that I referenced, yes.

12 Q. I see. Okay. Looking just at the 50
13 acres for the power block and the 75 acres for the
14 cooling pond --

15 A. (Mr. Major) 750 acres.

16 Q. I'm sorry. I dropped a zero. 750 acres
17 for the cooling pond, can you tell me how much of
18 the \$70 million site development estimate will be
19 used for work on that acreage?

20 A. (Mr. Major) I can give you a ballpark
21 percentage and say 70 to 80 percent of it. I'd
22 have to do a more detailed analysis.

23 Q. Well, that's fine for our purposes. You
24 think about 70 to 80 percent of that \$70 million is
25 going to be used on the power block site and the

1 cooling pond site?

2 A. (Mr. Major) Yeah. And, now, keep in mind
3 that in constructing the cooling pond, which we've
4 said is defined by existing dams that were on the
5 property, all of the fill requirements needed to be
6 removed there in order to create the cooling pond.
7 So we have actually created more than just the
8 50-acre power block in the process of excavating
9 the cooling pond and placing the fill where it's
10 ultimately going to be required. But, yeah, I'd
11 say that 70 to 80 percent of the work -- of the
12 dollars went into the scope of work that was
13 required to prepare the site for the first power
14 block.

15 Q. I'm not sure I understood that last
16 explanation. Let's try to get at it a different
17 way. Originally was your power block site under
18 water?

19 A. (Mr. Major) Yes. The majority of it was
20 under water.

21 Q. How many acres of the 800 acres that
22 we're talking about here between the cooling pond
23 and the power block site, how much of that was
24 under water?

25 A. (Mr. Major) Well, I would say in terms of

1 the cooling pond area, half of it would have been
2 under water because it was reclaimed land where
3 they have windrows when the phosphate industry
4 mined it, so roughly half of it would have been
5 under water. And I would say that of the power --
6 of the total power block area, that 900 acres where
7 the ultimate build-out will occur, half of that was
8 likely under water. And the specific 50 acres
9 where the initial units go, it was probably all
10 under water.

11 Q. Now, how much material did you have to
12 move to prepare the -- let's go with the whole
13 power block site, the 900 acres, and then the 750
14 acres for the initial cooling pond, how much
15 material did you have to move?

16 A. (Mr. Major) We moved -- we will have
17 moved upon completion roughly 10 million cubic
18 yards.

19 Q. Now, that's 10 million cubic yards to
20 construct a cooling reservoir?

21 A. (Mr. Major) Of fill that essentially came
22 out of the cooling reservoir, yes.

23 Q. Okay. Now, how much fill material did
24 you need for the power block and fuel storage
25 areas?

1 A. (Mr. Major) I believe that for -- well,
2 all of the 10 million cubic yards that came out of
3 the cooling pond were deposited in the power block
4 area, in part where the fuel storage area goes. I
5 think for ultimate build-out with a coal
6 technology, there may still be a shortfall of
7 roughly 3 million cubic yards.

8 Q. So as far as you can tell, in total you
9 only have had to move 10 million cubic yards of
10 material in preparing the site for this first
11 phase?

12 A. (Mr. Major) Yes.

13 Q. All right. Now, what costs do you
14 associate with moving that material, 10 million
15 cubic yards of material?

16 A. (Mr. Major) I'm not sure I understand.
17 What costs do I associate with that?

18 Q. Yes. Going back to the \$70 million
19 number that we extracted from Exhibit E --

20 A. (Mr. Major) Yes.

21 Q. -- how much of that \$70 million would you
22 attribute to movement of this 10 million cubic
23 yards of material?

24 A. (Mr. Major) I would have to do a detailed
25 review of the contract that we have with Brown &

1 Root. The approximate value of that contract was
2 \$29 million. And that included moving 10 million
3 cubic yards of fill material, putting soil cement
4 on the interior areas of the cooling pond dams,
5 constructing an intake structure, and clearing the
6 site. So I'd say a good portion of the \$30 million
7 went into the fill-related activities.

8 Q. Okay. Now, what additional site
9 preparation, mitigation, reclamation costs did you
10 incur out of that \$70 million associated with the
11 power block area and the cooling pond?

12 A. (Mr. Major) There were consulting fees.
13 And I'd have to get out the detail on that. As I
14 mentioned, there were -- there are AFUDC costs that
15 we're carrying on the site development. I'm not
16 sure I've got a detailed breakdown on what those
17 are.

18 There were -- there were several million
19 dollars of drainage requirements that were a
20 condition of certification to convey waters off of
21 the adjoining Estech properties to the
22 headquarters, headwaters of McCullough Creek.
23 There are costs for a brine storage pond and
24 initial solid waste disposal area that are being
25 constructed that go into part of that \$70 million

1 dollars. And, of course, we've already taken out
2 the USAC and the 2-1/2 million for the treated
3 effluent line for the City of Bartow.

4 Q. So those items that you just mentioned
5 plus the 29 million for the actual moving of the
6 material added up to the 70 to 80 percent of the
7 \$70 million number that you alluded to at the
8 outset of this part of our conversation?

9 A. (Mr. Major) Yeah.

10 Q. Now, how was the balance or how will the
11 balance of that \$70 million be spent?

12 A. (Mr. Major) There will be -- there will
13 be some mitigation of an area on the Estech
14 properties west of County Road 555 where we will
15 have to plant palmetto bushes and create an uplands
16 environment. And there will be some clay
17 consolidation that is ongoing in the areas north of
18 the cooling pond, and there will be some up-front
19 work that gets done in the buffer areas.

20 Q. So what dollar amount would you attribute
21 to each of those -- those activities?

22 A. (Mr. Major) I can't specifically give you
23 a dollar amount for those.

24 Q. So given the activities that we've
25 mentioned that will account for the \$70 million in

1 site development expense that you expect to
2 incur --

3 A. (Mr. Major) Yes.

4 Q. -- how many acres are we talking about
5 that are affected by those expenditures? Ballpark
6 is fine. I don't need an exact number.

7 A. (Mr. Major) I'd say 4,000 acres, half,
8 roughly half the site.

9 Q. How many miles of roads, paved roads,
10 will you be building on the site?

11 A. (Mr. Major) I'd say roughly -- roughly
12 three miles.

13 Q. Three miles of paved roads?

14 A. (Mr. Major) Yeah.

15 Q. Any other road-related improvements that
16 you're going to have to construct?

17 A. (Mr. Major) Not to the best of my
18 knowledge, no.

19 Q. Do you have a cost associated with that
20 work?

21 A. (Mr. Major) The roads and the paving,
22 that is included in the plant cost, not part of the
23 site development, but, no, I don't have a specific
24 break-out. We've got an estimate for it in the
25 detailed plant forecast.

1 Q. Are you going to be constructing a
2 railroad spur and making improvements to a railroad
3 spur on the site?

4 A. (Mr. Major) There is an existing rail
5 facility that is contained on our property. We'll
6 likely install a switch and 100 yards or so of
7 track where we can unload our heavy equipment.
8 That's the current plan.

9 Q. And what cost do you associate with the
10 work associated with the railroad spur?

11 A. (Mr. Major) Less than a quarter of a
12 million dollars, and that's included in the plant,
13 plant-related costs.

14 Q. Is your revegetation cost included in the
15 \$70 million number that we've been using?

16 A. (Mr. Major) There was a county
17 requirement to plant a buffer area adjacent to
18 County Road 555. That is included. There are
19 some -- there are some plantings required in the
20 buffer area along the east side of the property
21 that's part of the \$2 million additional that I had
22 referenced that was not part of the \$70 million we
23 arrived at.

24 Q. So that's what brings the total up to
25 roughly 113 million?

1 A. (Mr. Major) Yes. Yes.

2 Q. Are you going to have to dig water wells
3 on the property?

4 A. (Mr. Major) The initial requirements for
5 plant cooling are all being satisfied by
6 capturing -- the combination of capturing rainwater
7 on site and channeling it to the cooling pond or
8 the treated effluent from the City of Bartow.
9 We're currently evaluating whether our potable
10 water supply will be piped from the City of Bartow
11 or the City of Fort Meade or whether we're going to
12 put wells in for that. But those costs are
13 included in the plant, plant cost estimate.

14 Q. Now, for the intermediate and ultimate
15 build-out, 1,500 megawatts and 3,000 megawatts,
16 will you need to dig wells to support that level of
17 activity?

18 A. (Mr. Major) That depends on our timing
19 and success of getting additional treated effluent
20 sources. We currently have negotiations undergoing
21 with several other entities for additional water
22 sources. We're reasonably confident that we can
23 get the water from treated effluent and not be
24 required to put wells in.

25 The permit that we were issued by

1 Swiftmud did provide for an ultimate allowance, so
2 to speak, of I think 15 million gallons per day of
3 groundwater from wells, but the stipulation that
4 every attempt be first made to secure that through
5 other means, such as treated effluent and
6 conservation, whatever.

7 Q. If you're required to resort to wells, do
8 you have any estimate of what that cost would be?

9 A. (Mr. Major) There were some estimates
10 prepared during the course of the project. I don't
11 have those with me. I'd have to dig out our files
12 to see what those estimates are.

13 Q. Do you have any ballpark sense of what
14 the dollars were?

15 A. (Mr. Major) Yeah. I believe that on a
16 per-well basis it was somewhere a million, million
17 and a half dollars.

18 Q. And how many wells in a worst case would
19 you have to dig?

20 A. (Mr. Major) For the initial --

21 Q. Well, for each of the initial,
22 intermediate, and ultimate build-out.

23 A. (Mr. Major) I think we were looking at
24 two wells being required for the initial block if
25 we were to go with wells. I can't recall what the

1 total number was for ultimate.

2 Q. Ballpark?

3 A. (Mr. Major) Ballpark, ballpark, I think
4 it was six to eight.

5 Q. And are those costs reflected at all in
6 the \$70 million?

7 A. (Mr. Major) No, they're not.

8 Q. In the plant cost?

9 A. (Mr. Major) No. Well, we have our needs
10 satisfied for the first 470. And, well, we
11 actually feel we have our needs satisfied for the
12 first 1,000 megawatts of generation that goes
13 there, taking into account the treated effluent
14 from the City of Bartow plus water that we'll
15 capture from rainfall.

16 Q. Have you incurred any expense for
17 off-site mitigation?

18 A. (Mr. Major) No.

19 Q. So you haven't been required to buy
20 property elsewhere and donate that?

21 A. (Mr. Major) Well, the wildlife corridor
22 contribution that we made, the properties that we
23 bought from Estech, that was roughly \$400,000. But
24 that was the only requirement that we had for any
25 off-site mitigation. And those costs were included

1 in the site development.

2 Q. I'd like to talk a little bit about the
3 Exhibit B. Exhibit B represents the cost
4 effectiveness studies that you did in '94 in
5 connection with the Polk project?

6 A. (Mr. Major) Yes.

7 Q. Are you familiar with the concept of sunk
8 costs?

9 A. (Mr. Major) Yes.

10 Q. At the time of the study, had FPC
11 incurred any sunk costs?

12 A. (Mr. Major) Yes, we had.

13 Q. How would you define sunk costs?

14 A. (Mr. Major) Well, it's we define it as
15 they were monies expended on the project that if
16 you no longer go forward with the project, you
17 don't recover those costs in any fashion.

18 Q. What estimate of sunk costs did you
19 consider in your February '94 cost effectiveness
20 study?

21 A. (Mr. Major) I need to refer to that
22 document, but I think it was somewhere around 28 or
23 \$30 million dollars. 27.

24 Q. Tell me what that figure consisted of.
25 What did those costs consist of?

1 A. (Mr. Major) Well, let me -- let me
2 qualify that I'm not sure I would say that all of
3 those were sunk costs. Those were costs that we
4 had expended to date when this study evaluation was
5 done. And that included the site selection cost,
6 the cost that had gone into the need hearings, site
7 certification, and licensing, consulting services,
8 land options money at that time, and the relocation
9 of the clay pipeline with IMC.

10 Q. Does that number include any cancellation
11 costs that you might have in connection with
12 contracts entered into, penalty payments of any
13 kind?

14 A. (Mr. Major) No. Because I'm not sure any
15 of the contracts that we had at the time would have
16 had us assigned with any penalties.

17 Q. In what way did you consider those sunk
18 costs in your evaluation?

19 A. (Mr. Major) Well, they were -- they were
20 certainly considered part of the project costs for
21 the option of going forward with Polk. They
22 were -- I believe we looked at going forward with
23 an option on smaller parcels. And part of those
24 costs were assumed as being part of that project
25 cost, and then there was an option that looked at

1 repowering, and I think part of those costs were
2 just discounted, you know, that those would
3 probably be true sunk costs.

4 Q. Do you have an estimate of your sunk
5 costs today?

6 A. (Mr. Major) I've got an estimate of total
7 project cost to date.

8 Q. Would you consider that number to
9 represent your sunk costs to date?

10 A. (Mr. Major) I would, in terms of dollars
11 that have been expended on the project.

12 Q. If we're looking at the sunk costs
13 estimate today, would that estimate include
14 cancellation fees associated with contracts that
15 you entered into?

16 A. (Mr. Major) If we were looking at it
17 today, I would have a high level of confidence that
18 these numbers would be truly representative of sunk
19 costs. Now, if we were looking at this six months
20 from now, with Westinghouse having gone forward
21 with additional engineering and some commitments on
22 their equipment contracts, then that number would
23 be different.

24 Q. Different in what respect?

25 A. (Mr. Major) Well, it would be higher

1 because of some liabilities that we may have
2 incurred under that contract.

3 Q. You mentioned in your '94 study you
4 looked at an alternative that involved going ahead
5 with what you called postage stamp sites at the
6 Polk site?

7 A. (Mr. Major) Yes.

8 Q. Can you explain a little bit more what
9 that involved?

10 A. (Mr. Major) That involved taking a look
11 at reducing the size of the site, and it consisted
12 primarily of the Estech properties on how small of
13 a parcel that we could develop and put the I think
14 limited power output on them, on the Estech
15 properties.

16 Q. Did that alternative look at siting the
17 same amount of generation on smaller parcels?

18 A. (Mr. Major) Yes.

19 Q. And why did you reject that alternative?

20 A. (Mr. Major) Well, I think I mentioned
21 that when we compared the various options, there
22 were some early on economics, but longer term when
23 you consider the future expansion needs of our
24 system in terms of a ten-year analysis or so, that
25 on a life cycle cost basis, the larger site with

1 the economics of incremental unit additions going
2 on the larger site, proved out that the life cycle
3 economics favored the original site development
4 that had been projected.

5 Q. At this point is it the company's
6 expectation that your next several units up to
7 3,000 megawatts will be sited at this Polk site?

8 A. (Mr. Major) I think our current plan is
9 still consistent with -- well, I think in our
10 current ten-year site plan, we do have the Higgins
11 and Turner repowerings in there in advance of the
12 next blocks of generation going at Polk. Those --
13 as I can recall, those costs are very close in
14 terms of putting units at Polk first in lieu of the
15 repowerings, but I think the economics still
16 dictate that the repowerings, at the time the last
17 studies were being done, that those were in the
18 ten-year site plan.

19 A. (Mr. Niekum) If I could add something on
20 that, in the production of the ten-year site plans,
21 there are other issues besides the absolute
22 straight economics of simply a site unit at Polk
23 versus a repowering site due to some of the
24 transmission constraints or availability of natural
25 gas pipeline capacity somewhere else, and the

1 chance to use some of the existing equipment that
2 already exists, there is other opportunities and
3 those repowerings have generally looked favorable,
4 but the economics between incremental units at Polk
5 and the repowerings are very close, and we've tried
6 to always indicate that that's a tough choice.
7 There's nothing compelling about one or the other.
8 They are very close.

9 Q. But putting aside the repowering
10 alternative, looking into the future in terms of
11 siting incremental generation, is it your intention
12 that all of your incremental generation up to the
13 3,000 megawatts will be sited at the Polk site?

14 A. (Mr. Niekum) If I can add onto that too,
15 well, it depends on what you need. We would
16 probably not take a site like Polk County and add a
17 combustion turbine there. We have other sites that
18 are capable of handling combustion turbines. And
19 the Polk site, due to its infrastructure and design
20 as more or less a base load plant site, would be
21 the logical place to build a base load or
22 intermediate plant. But if our next need were a
23 combustion turbine, it's not likely that that
24 increment of generation would be at Polk.

25 Q. So you think it's important to have other

1 alternative sites that you can consider in the
2 future in addition to the expansion capability at
3 Polk, depending on the need?

4 A. (Mr. Niekum) Depending on the need, the
5 technology, the transmission constraints and a
6 number of factors, but for intermediate or base
7 load capacity that you may want to add on our
8 system, the economics of Polk look very good for
9 the incremental new capacity.

10 Q. I'd like to ask you a few questions
11 about the gas supply for your Polk unit. At this
12 point in time, have you entered into any gas supply
13 or transportation contracts for the Polk site?

14 A. (Mr. Niekum) We have entered into a
15 number of contracts for natural gas pipeline
16 capacity on the Florida Gas Transmission system.
17 We signed capacity release agreements with five
18 municipal agencies that had capacity that they were
19 willing to release permanently. And we have signed
20 contracts with them. They have made the capacity
21 release available to us, and we've signed service
22 agreements with FGT to take that capacity.

23 So we have obtained approximately on
24 average -- it varies month to month, but on average
25 about 47,000 a day, million MMBTUS a day, to the

1 Polk site for transportation capacity. We own some
2 other transportation capacity on our system that
3 could be transferred to Polk as an alternative
4 delivery point. Our University of Florida project
5 has roughly about 9,500 a day. And we took some
6 capacity on FGT's system of about 4,000 a day that
7 we moved to our Bartow plant or our Intercession
8 City peakers or our Higgins peakers. So some of
9 that capacity could also be made available to Polk.

10 We have also been a participant in
11 Florida Gas Transmission's 1998 expansion, which is
12 to go in-service in spring of '98, and we're a
13 participant in that expansion, and we have agreed
14 to take some capacity from that.

15 Q. Now, the capacity that you've been able
16 to capture from the secondary market, is that firm
17 capacity?

18 A. (Mr. Niekum) Yes.

19 Q. It is?

20 A. (Mr. Niekum) Yes.

21 Q. And what is that going to cost you?

22 A. (Mr. Niekum) The capacity is generally a
23 blend of -- well, maybe it takes a bit of
24 explanation. Florida Gas Transmission has two
25 rates for their firm transmission capacity. FTS-1,

1 which is Phase 1 and 2 of the FGT system, and then
2 FTS-2, which is Phase 3 of the FGT system, which is
3 a little confusing. The capacity we bought was
4 both FTS-1 and FTS-2. The FTS-1 firm rate is
5 approximately 43 cents a million BTUs, and the
6 FTS-2 is approximately 76 cents. The blended rate
7 that we got on the capacity lease market will
8 probably be somewhere on average around 55 cents.
9 So it was considerably less than pure expansion
10 capacity.

11 Q. Now, you mentioned that you're also
12 subscribing to the 1998 expansion that FGT is
13 planning?

14 A. (Mr. Niekum) Yes.

15 Q. How much capacity are you subscribing for
16 there?

17 A. (Mr. Niekum) This is an element that
18 because we have not disclosed that to anyone and
19 FGT has not formally filed their application for
20 that expansion, that we have been -- we have
21 considered that a confidential piece of information
22 until that filing is made. That filing should be
23 made -- in our last discussion with FGT, they said
24 by the end of this month, and then it will be
25 public. But there were some sensitive negotiations

1 that were involved in exactly how that would take
2 place and the quantities and the way it would be
3 delivered that were confidential until the
4 application was actually filed.

5 Q. Do you expect that to be firm capacity?

6 A. (Mr. Niekum) Yes.

7 Q. What's your estimate of what that's going
8 to cost?

9 A. (Mr. Niekum) It will be at the maximum
10 FTS-2 rate, which will be about 76 cents a million
11 BTUs for that capacity. As part of FGT's tariff,
12 they can't do an expansion that would cause any
13 rise in the rates of their Phase 3 expansion. So
14 for them to do an expansion, they have to roll in
15 the costs at a rate that doesn't cause the rates of
16 any other shippers to be increased.

17 Q. In terms of your needs at the Polk plant,
18 how important is it to you to be able to get the
19 capacity from FGT's '98 expansion?

20 A. (Mr. Niekum) Well, it's an obvious major
21 component of our mix. But we have -- there are
22 still possibilities in the secondary market if for
23 some reason that capacity didn't appear. There
24 are -- we could still look at another expansion if
25 for some reason this one were rejected, and we can

1 probably transfer some of our existing pipeline
2 capacity in the worst case scenario. There is also
3 a very active market in short-term release capacity
4 that would be a possibility for some period of time
5 until some firm capacity could be had.

6 So it's a little hard to answer that
7 question. You would have to take the circumstance
8 as it occurs and try and do whatever it would take
9 to find the capacity that you needed. And I guess
10 your ultimate choice would be you'd have to take
11 the capacity that you have and change your
12 operation of the plant to operate with what you
13 already have.

14 Q. What's your sense of how much additional
15 capacity is available on the secondary market?

16 A. (Mr. Niekum) My understanding is that
17 there is more out there because it's fully expected
18 that there will be intervenors in FGT's expansion
19 case by shippers that want to sell back capacity to
20 FGT. So it would be a bit of speculation to know
21 how much is out there and how much people are going
22 to say they don't want.

23 Our experience has been that people don't
24 want to really admit they have more capacity than
25 they need because it makes them, for whatever

1 internal reason, look like they've made a mistake.
2 But when someone is actively out there buying, then
3 they generally will come forward with what they
4 might be willing to sell.

5 Q. Are you confident that you can find
6 enough additional capacity in the secondary market
7 to replace the '98 expansion capacity if you had to
8 do that?

9 A. (Mr. Niekum) I don't know whether you
10 would get it quite under the same terms and
11 conditions as the FGT expansion. I'm confident
12 that there are ways of getting capacity either
13 permanently or through short-term deals over a
14 period of time until either another expansion
15 occurs or there's a competing pipeline or some
16 other alternative, that there is enough flexibility
17 in the gas transportation market now after 636 that
18 in general if you're willing to pay for it, you can
19 find it.

20 Q. So you wouldn't expect this capacity, if
21 you could find it, to be cheap?

22 A. (Mr. Niekum) Well, it's limited by FERC
23 rules currently that no one can sell at more than
24 max rate. I would expect if there's a surplus
25 of capacity, it will be very cheap. There is

1 capacity, FTS-2 capacity on FGT'S system that
2 currently sells for 2 cents on certain months, and
3 on other months, of course, it sells at max rate or
4 it isn't available.

5 So I would expect that you could get some
6 quantities cheap. You may pay some premiums at
7 some times. It would depend on the market
8 conditions of what you would find for
9 transportation. So my expectation would be is you
10 could find it at a reasonable price. It may be
11 expensive sometimes; it may be extremely
12 inexpensive at others.

13 Q. How much gas will you need to operate the
14 Polk plant as it's currently designed?

15 A. (Mr. Niekum) Well, that's another
16 sensitive point right now because if you took the
17 amount that we say we need at Polk and subtracted
18 out what we've already obtained, you pretty much
19 know what we've taken in the expansion capacity.
20 So it kind of rolls into that same issue. Until
21 the expansion capacity is made public, we haven't
22 really said how much gas we would use at Polk.

23 It also depends a bit on how the unit
24 dispatches on our system. There is a certain issue
25 on how much -- how it sits relative to coal, any

1 off-system sales you may make. So there is a
2 certain variable there that you may adjust your gas
3 supplies to match how much you think you're going
4 to run the unit.

5 Q. Have you incurred or do you expect to
6 incur any reservation charges or premiums in
7 connection with the capacity that you've gotten
8 from the secondary market or in connection with the
9 FGT Phase 3 capacity?

10 A. (Mr. Niekum) I'm not clear on what you
11 mean by reservation charges on that capacity.
12 Right now we own it.

13 Q. Okay. What about -- I'm sorry.

14 A. (Mr. Niekum) We own the capacity, and
15 it's simply ours to use. We pay the tariff and the
16 variable cost to ship gas on it.

17 Q. What about the Phase 3 capacity?

18 A. (Mr. Niekum) That would be pretty much
19 the same thing. We would own the capacity at the
20 maximum rate, and our use of it would be our own
21 choice. We could use it or sell it.

22 Q. So there's no premium that you would
23 expect to have to pay?

24 A. (Mr. Niekum) Only if there were problems
25 with FGT getting the FERC approval for their

1 expansion capacity for some reason, and then there
2 might be some reason that we would have to pay some
3 premium to get capacity built, but our expectation
4 is that the expansion will be approved and the
5 rates will be rolled in at FTS-2.

6 Q. Could I borrow Exhibit B again, please.
7 Thank you. I'd like to ask you to take a look at
8 the second page of Attachment I to Exhibit B under
9 the pros paragraph No. 3.

10 A. (Mr. Major) Yes.

11 Q. Would you read that for the record and
12 then explain what is meant. Why is that a pro?

13 A. (Mr. Major) "Polk units are important to
14 the gas pipeline profitability in the 1998 and
15 beyond time frame. The company also has a
16 significant need and use for the fiber-optic
17 component of the pipeline."

18 That's when we were in the -- we were a
19 partner in the SunShine Pipeline. And as Bob had
20 previously mentioned, the Anclothe unit anchored the
21 pipeline, but the initial need for that pipeline
22 was demonstrated by gas burn at Anclothe and Polk
23 County. And that was just a statement that the
24 Polk County site in terms of value that it was key
25 to making the pipeline profitable unless other

1 sources of transportation were sold off that
2 pipeline.

3 The fiber-optic -- it says, "The company
4 also has a significant need and use for the
5 fiber-optic component of the pipeline." There was
6 talk, I think, early on that if the pipeline --
7 when the pipeline went in, we would put fiber-optic
8 cable in with the pipeline, but I'm not sure that
9 that was ever a significant or serious
10 consideration. Bob, you may know more about it
11 than I do.

12 A. (Mr. Niekum) I think the biggest issue
13 there was maintaining our rights for the
14 fiber-optic. We weren't sure where that was
15 going. We thought that by simply maintaining our
16 rights to have a path for fiber-optic cable, we had
17 an asset that would be valuable. But I'm not sure
18 myself how far we really got with exploring markets
19 for that whole idea.

20 Q. So was the potential value of this
21 fiber-optic easement taken into account in any way
22 in your cost effectiveness evaluations or the
23 choice of natural gas as a fuel?

24 A. (Mr. Major) I would -- from my
25 perspective, I see that as having been handled as

1 an intangible. It was one of those nice-to-do
2 things, but I don't believe there were any
3 economics ever associated with it.

4 A. (Mr. Niekum) I might add there may be
5 some economics that were done when the SunShine
6 Pipeline was looking at its profitability, and it
7 may have been done there, but I don't know of any
8 of it being used in our evaluations of Polk County.

9 Q. I'd like to ask you to look at really
10 it's the first page of text in Exhibit B. It's
11 headed "Energy Supply, FPC Polk County Site." The
12 fifth paragraph down states that, "Polk County is
13 the only generation alternative under
14 consideration which offers fuel flexibility and
15 alternatives to over-reliance on natural gas."
16 Would you take a look at that paragraph.

17 A. (Mr. Major) Yes.

18 Q. Can you tell me what was meant by that
19 first sentence in the paragraph?

20 A. (Mr. Major) Okay. When we -- as I said,
21 we looked at three alternatives scenarios, and the
22 variations off of Polk were essentially building
23 the units on smaller parcels or doing repowering
24 ahead of Polk and then putting the Polk units on
25 smaller parcels wherever they may be selected.

1 And I think that our -- that statement
2 alludes to the fact that if the unit was placed on
3 a smaller parcel, then likely there would be no
4 coal capability in the future, and it's referring
5 that of these scenarios, which were the most
6 competitive scenarios as we envisioned them, that
7 Polk County on the large parcel was the only one
8 under consideration which offered us the fuel
9 flexibility, principally coal capability, and
10 alternatives to natural gas.

11 Q. Can you tell me what other units on your
12 system use natural gas as a fuel?

13 A. (Mr. Niekum) We have several combustion
14 turbine sites that use natural gas. Our Avon Park
15 peakers, which are some small units roughly 60
16 megawatts total. Our Higgins peakers in Pinellas
17 County, which are four units approximately 50
18 megawatts each, I think 45 megawatts each.

19 Our Intercession City peakers that have
20 just been -- we converted two of those units last
21 year in August and we converted two more this
22 month, so we have a total of four units there each
23 approximately 85 megawatts in the summer that have
24 been converted to natural gas.

25 We have one steam plant in Pinellas

1 County, Bartow 3, which is a 200-megawatt oil
2 plant, burns heavy oil and is capable of burning
3 100 percent natural gas. And our Suwannee River
4 plant, which is not on the FGT system, it's on the
5 South Georgia Gas system, which is approximately
6 150 megawatts with three units there. One is 75
7 megawatts. The other two are like 36 megawatts
8 each. All three units there are capable of natural
9 gas.

10 And our University of Florida cogen
11 project, which is about 40 megawatts that
12 supplies -- it's an electric plant but also
13 supplies steam to the University of Florida.

14 Q. Which of those units is served on an
15 interruptable basis and which is served on a firm
16 basis?

17 A. (Mr. Niekum) The University of Florida
18 project is the only one that has both firm gas
19 transportation and firm gas supply. All of the
20 others operate on a combination of interruptable
21 supply or short-term firm. And we try to have a
22 portfolio of capacity. That is, sometimes we may
23 buy for the summer, sometimes we buy for a month,
24 sometimes we buy for a day. Sometimes it's
25 recallable, sometimes it isn't.

1 There is no -- when you're buying gas for
2 combustion turbines whose operation is problematic,
3 you don't buy gas long-term, you buy it short-term,
4 trying to match your burns with your gas
5 purchases. So oftentimes those purchases are firm
6 but for a short period of time. And we don't
7 always have a guarantee that the next time we need
8 it, it will be there. So you would buy your gas
9 that way for units that are dual fuel capable.

10 We had some firm transportation at our
11 Suwannee River plant on the South Georgia system
12 which we have gone through a capacity sale and swap
13 arrangement with Proctor and Gamble in Albany,
14 Georgia, and the City of Tallahassee to by the end
15 of this year get rid of that firm transportation
16 and we're operating that plant more on short-term
17 firm and interruptable.

18 So the answer to your question is that
19 except for the University of Florida, very little
20 is firm year-round but it is firm on the
21 short-term.

22 Q. The fuel price forecasts in Exhibit A,
23 did those prices include transportation, or were
24 they just commodity prices?

25 A. (Mr. Niekum) No, those were the delivered

1 cost, which was the transportation both fixed and
2 variable and the commodity cost.

3 MR. LONG: I'd like to take a very short
4 maybe a five-minute break. I think I'm pretty much
5 done, but I just want to see if I have anything
6 else to bring up.

7 (Brief recess.)

8 BY MR. LONG:

9 Q. I really appreciate your patience. I
10 have a couple of more questions, and then we're
11 finished.

12 I'd like to ask about the outside gas and
13 oil forecasts that you used in connection with
14 developing your own forecasts. First, at the time
15 of Exhibit A, can you tell me what outside
16 forecasts you consulted?

17 A. (Mr. Niekum) At the time of Exhibit A,
18 I'm really not sure. I believe that most of that
19 was done through internal forecasting, and I'm not
20 sure what references were used back then. That
21 was -- I wasn't in the fuels department at that
22 time. I remember receiving it. And at that time I
23 believe we subscribed to a number of industry
24 forecasting magazines and services, but we didn't
25 really have a consultant full-time looking at those

1 price forecasts. So it was probably done
2 internally based upon some industry data.

3 Q. When you say "industry data," you mean
4 external forecasts done by others?

5 A. (Mr. Niekum) I think they would aggregate
6 different forecasts from DOE. Maybe different
7 consulting groups would put out forecasts, oil
8 companies would put out forecasts. I don't think
9 there was a formal process, but you would aggregate
10 those you tended to believe and those you did not
11 and took what you knew from vendors and what you
12 were paying and tried to make a forecast out of
13 that data.

14 Q. What about currently, can you tell me
15 what outside forecasts you use?

16 A. (Mr. Niekum) Our general gas and oil
17 forecasts are done by PIRA. It's Petroleum
18 Industry Research Associates. It's one of several
19 major consulting groups that do this type of
20 forecasting. The PIRA is one that we consider
21 reasonably neutral in that they produce forecasts
22 both for producers and customers, so they have a
23 little more incentive to not bias the results too
24 much one way or the other.

25 Fuel forecasting is fairly difficult, but

1 we've been reasonably satisfied that their methods
2 and their forecasts, while not perfect, have been
3 reasonably accurate for the last year or two, and
4 we've been using their data as the primary source,
5 but we always reserve the right, if we just think
6 that they've gone off on a tangent, to do something
7 else, but in general our forecasts follow PIRA.

8 Q. During the course of the day there have
9 been a number of questions about your cost
10 effective analysis for your unit and your economic
11 analysis for your system. Would you agree that a
12 unit that's cost effective on one utility's system
13 may not be the most effective option on another
14 utility's system?

15 A. (Mr. Niekum) Yes, I would agree with that
16 statement.

17 MR. LONG: Well, thank you. I have
18 nothing else. I really appreciate your time.

19 MR. MCGEE: I have nothing.

20 EXAMINATION

21 BY MR. ELIAS:

22 Q. I just have a couple follow-up questions
23 and then a couple of formalities that we need to
24 take care of.

25 Mr. Long asked you a couple of questions

1 concerning the combination of a low coal and high
2 natural gas forecast. Do you recall those
3 questions?

4 A. (Mr. Niekum) Yes.

5 Q. How likelihood -- how likely are both of
6 those scenarios to occur at the same time?

7 A. (Mr. Niekum) The likelihood would
8 probably be very small. The low forecast and the
9 high forecast are based on the fact that there
10 could be economic conditions that would cause all
11 the fuel prices to be low or all the fuel prices to
12 be high. For the probability of one particular
13 fuel to go down while the others went up is
14 probably very small. And it can happen over short
15 periods of time due to production disruptions or
16 strikes or things that could cause it to happen.

17 Over an extended period of time, I guess
18 our viewpoint would be there's a tendency for the
19 market to cause the prices to go more closer to an
20 equilibrium. So I would say the likelihood is very
21 small that that would happen.

22 Q. During a series of questions about the
23 site development costs of your Polk facility,
24 mitigation was mentioned quite often. Is the
25 mitigation that you're going to have to do a result

1 of the decision to build a power plant on that site
2 or the fact that it was mined-out phosphate land?

3 A. (Mr. Major) In my opinion, it was driven
4 by the fact that we were putting a power plant site
5 on the property, a power plant on the property.

6 Q. And when you say in your opinion, first
7 of all, the requirements were imposed by various
8 state agencies?

9 A. (Mr. Major) The requirements were imposed
10 by state agencies or federal agencies in the case
11 of the corps of engineers, although they did concur
12 with what we were doing at the request of the state
13 agencies. The primary true mitigation that we're
14 doing is in the buffer areas and establishment of
15 the wildlife corridor, and those would not have
16 been requirements placed upon the mining
17 companies. So it was -- we kind of viewed that as
18 it was mitigation for the impacts that the state
19 agencies saw the power plant placing on that local
20 area.

21 Q. And Mr. Niekum, you answered a series of
22 questions about the various natural gas units on
23 Florida Power Corp.'s system. How many of those
24 natural gas units are capable of burning more than
25 one fuel?

1 A. (Mr. Niekum) They are all capable of
2 burning more than one fuel except for the
3 University of Florida cogen plant.

4 Q. And what other fuels are they capable of
5 burning?

6 A. (Mr. Niekum) The Bartow 3 and the three
7 small units at Suwannee River plant are capable of
8 burning No. 6 oil. The other turbines at Higgins,
9 Avon Park, Intercession City are capable of burning
10 No. 2 oil, distillate fuel.

11 Q. And am I correct there is no backup or
12 alternative fuel for the University of Florida
13 cogen facility?

14 A. (Mr. Niekum) Currently there is not. We
15 are looking at some short-term possibilities of
16 putting a fuel in there for a short duration peak,
17 but right now we have a very firm gas supply
18 contract and firm transportation, and we can always
19 take some of our other gas that we're burning
20 elsewhere on our system and divert it there if we
21 run into problems, so that unit doesn't currently
22 have that capability.

23 Q. Was -- which came first, was it the
24 decision to fuel the University of Florida project
25 with firm gas a requirement of the project, or was

1 the absence or the lack of suitability of backup
2 fuel the primary driver?

3 A. (Mr. Niekum) It was actually a technical
4 problem with the type of turbine that was put in
5 there that the turbine as it is currently designed
6 was not designed to handle dual fuel capability,
7 but the manufacturer had indicated that that
8 technology would eventually be available for that
9 unit. So the issue became one of due to the size
10 of the unit and the fact that firm gas was
11 available, we elected to use a gas-fired unit there
12 with no backup fuel under the assumption that if it
13 became a necessity to have backup fuel there, that
14 the technology would eventually be available to do
15 it.

16 A. (Mr. Major) And let me comment on that.
17 The turbine is not designed that it can readily be
18 fired between two different fuels. It can either
19 burn gas or it can burn distillate, but the
20 changeover is like a one-day process in order to
21 change fuel nozzles. And the thinking was that in
22 order -- by the time you change the fuel nozzles to
23 convert from one fuel to the other, the
24 availability of the other fuel would be there, and
25 then there would be another day to change it back.

1 So until the capability to shift while the unit was
2 running from one fuel to another, we didn't
3 envision much of an advantage in providing separate
4 fuel nozzles.

5 Q. A significant portion of the steam output
6 of that unit is used in Shands Hospital, is it not?

7 A. (Mr. Major) Yes.

8 Q. Do you know if that had anything to do --
9 if those requirements had anything to do with the
10 choice of how this unit was to be fueled; i.e.,
11 firm versus interruptable?

12 A. (Mr. Niekum) Well, there were two pieces
13 to that. One is that we had firm gas for that
14 unit. And, secondly, there are boilers there to
15 provide the steam in the event that the cogen plant
16 is not available. And I believe that there is
17 backup fuel for the steam boilers available. So
18 the event of the likelihood of running out of fuel
19 for the steam sale is extremely small because the
20 backup fuel is available for that.

21 Q. Do either of you have any plans to be in
22 the Tallahassee area the 17th or 18th of next
23 month?

24 A. (Mr. Major) No.

25 A. (Mr. Niekum) No.

1 Q. You expect to be in St. Petersburg
2 working?

3 A. (Mr. Major) Yes.

4 A. (Mr. Niekum) Yes.

5 MR. ELIAS: Then the only other question
6 is the reading of the deposition and the filing
7 date for the late-filed exhibits.

8 MR. LONG: Before we get on the
9 procedural matters, a couple of questions that were
10 prompted by yours. Actually, just one.

11 EXAMINATION

12 BY MR. LONG:

13 Q. I really hate to impose, but I need to
14 ask you to do one more calculation for me in
15 Exhibit A. Going from the year 2004 to 2010, would
16 you compare the high case coal price and the high
17 case gas price in each of those years, the
18 differential between the two.

19 A. (Mr. Niekum) Calculated the difference
20 between going from 2004 through 2010. In 2004 the
21 difference was \$5.78, in 2010 it was \$8.44, with a
22 fairly consistent escalation in that delta going
23 through those years.

24 Q. So the relationship for that period
25 didn't remain constant?

1 A. (Mr. Niekum) It expanded by roughly
2 \$2.60.

3 Q. And as I recall, you assign a 25 percent
4 probability to each of those high case forecasts?

5 A. (Mr. Niekum) Yes.

6 MR. LONG: Thank you. That's all I
7 have.

8 MR. ELIAS: Nothing further other than
9 the reading of the deposition, reading and
10 signing.

11 (Whereupon, the deposition concluded at
12 4:01 p.m.)

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25

SIGNATURE PAGE

This is to certify that we, ROBERT D. NIEKUM and ERIC G. MAJOR, have read the foregoing transcription of our testimony, page 1 through 199, given on June 4, 1996, in Docket No. 960409-EI, and find the same to be true and correct, with the exceptions and/or corrections, if any, as shown on the errata sheet attached hereto.

ROBERT D. NIEKUM

Sworn to and subscribed before me this
day of _____, 1996

NOTARY PUBLIC

State of _____

My Commission Expires: _____

ERIC G. MAJOR

Sworn to and subscribed before me this
day of _____, 1996

NOTARY PUBLIC

State of _____

My Commission Expires: _____

(DE 4250)

1 F L O R I D A)

2 COUNTY OF PINELLAS)

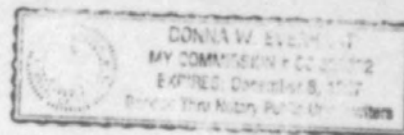
CERTIFICATE OF OATH

3
4 I, the undersigned authority, certify
5 that the witnesses appearing herein personally
6 appeared before me and was each duly sworn.
7

8 WITNESS my hand and official seal this
9 11th day of June, 1996.
10

11
12 Donna W. Everhart

13 Donna W. Everhart
14 CSR, RPR, CP, CM
15 Notary Public
16 State of Florida
17 Commission No.: AA 726903
18 My Commission Expires:
19 12/8/97



1 F L O R I D A)
 2 : CERTIFICATE OF REPORTER
 3 COUNTY OF PINELLAS)

4 I, Donna W. Everhart, CSR, RPR, CP, CM, Court
 5 Reporter and Notary Public in and for the State of
 6 Florida at Large, DO HEREBY CERTIFY that the
 7 foregoing deposition was taken before me at the
 8 time and place therein designated; that my
 9 shorthand notes were thereafter transcribed into
 10 this computer-assisted transcript under my
 11 supervision; and the foregoing pages numbered 1
 12 through 199, inclusive, constitute a true and
 13 correct record of the testimony given by the
 14 witnesses.

15 I FURTHER CERTIFY that I am not a relative,
 16 employee, attorney or counsel of the parties, nor
 17 financially interested in the foregoing action.

18 DATED this 11th day of June, 1996.

19 Donna W. Everhart
 20 Donna W. Everhart
 21 CSR, RPR, CP, CM
 22 Notary Public, State of Florida
 23 Commission No.: AA 726903
 24 My Commission Expires: 12/8/97



ERRATA SHEET

DOCKET NO.: 960409-EI
NAME: ROBERT D. NIEKUM
JUNE 4, 1996

DOCKET NO.: 960409-EI
NAME: ROBERT D. NIEKUM
DATE: JUNE 4, 1996
IN RE: Prudence review to determine regulatory
treatment of Tampa Electric Company's Polk Unit

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Please sign the transcript on page 10

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(DE 4250)

ERRATA SHEET

DOCKET NO. : 960409-EI

NAME: ERIC G. MAJOR

DATE: JUNE 4, 1996

DATE: JUNE 4, 1996
IN RE: Prudence review to determine regulatory
treatment of Tampa Electric Company's Polk Unit

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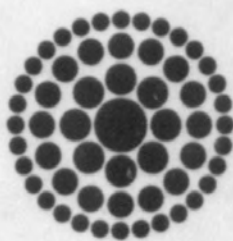
(DE 4250)

EXHIBIT A

DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJOR

DESCRIPTION: FLORIDA POWER CORPORTION POLK COUNTY
SITE NEED DETERMINATION STUDY

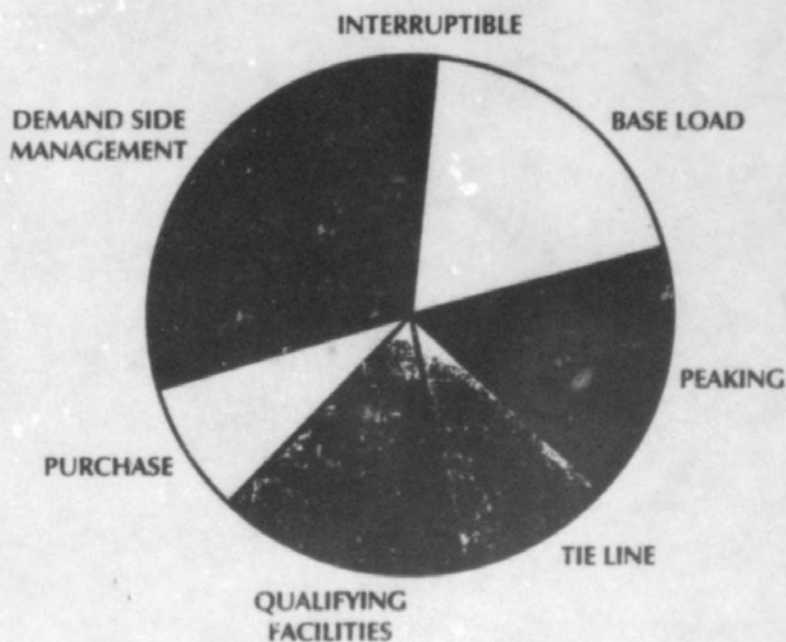


**Florida
Power**
CORPORATION

Docket No. 910759-EI

INTEGRATED RESOURCE STUDY

IN SUPPORT OF PETITION TO DETERMINE NEED FOR
ELECTRICAL POWER PLANTS



AUGUST 1991

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EXECUTIVE SUMMARY

system, the resource baseline largely consists of all existing FPC units and the DeBary and Intercession City peaking additions scheduled for 1992 and 1993, respectively.

The baseline for this IRP reflects very substantial purchases of capacity from QFs and other utilities. FPC now has about 1,000 MW of capacity under contract, in addition to its purchases of the Southern Company's capacity and interchange energy. As shown in Figure ES.4, FPC has purchased as much QF capacity as all other Florida investor-owned utilities combined.

These substantial QF purchases were a part of all of the generation expansion plans evaluated by FPC in this Study. FPC also evaluated the possibility of increasing the level of its purchases over and above present levels as one of its supply-side options. This evaluation, explained in greater detail below, indicated that such additional purchases would not be prudent.

FORMULATION AND EVALUATION OF GENERATION ALTERNATIVES

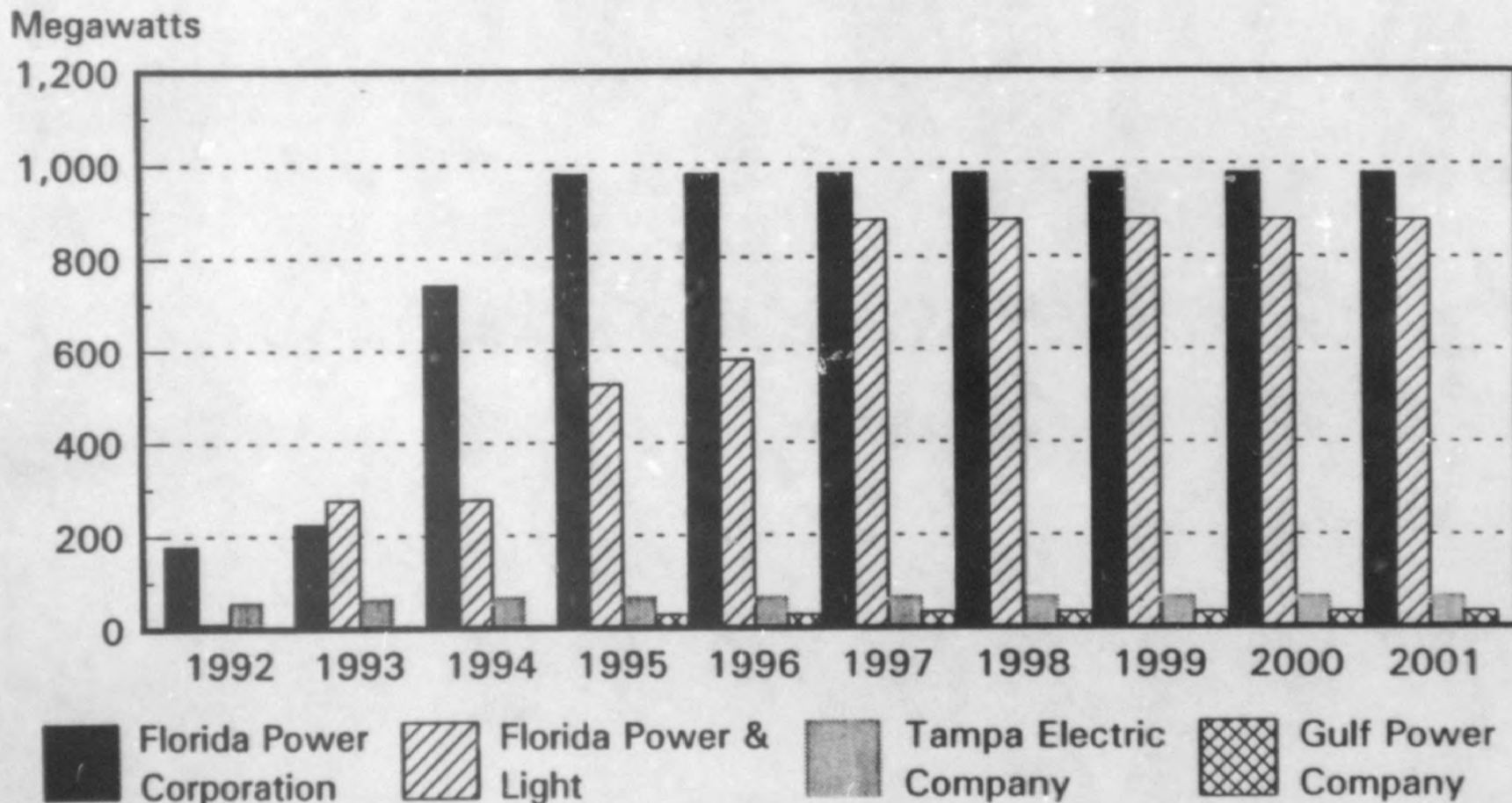
Following the establishment of its need for additional generation, FPC developed a set of 10 generation expansion alternatives. These alternatives were created and then evaluated to ensure that FPC examined and quantified the costs and benefits of a variety of generation expansion technologies, plant sizes, and construction options.

In developing its expansion alternatives, Florida Power had four major considerations. First, the technologies used in alternative plans must meet FPC's criteria for technical feasibility, reliability, and potential cost effectiveness. Second, the alternative plans must result in a system that meets or exceeds FPC's reliability criteria during each year of the plan. Third, the alternative plan must be consistent with FPC's commitment to environmental protection, and in particular must permit Florida Power to comply with the revised Clean Air Act limitations on sulfur dioxide emissions. Finally, the alternative must represent a plan that is well integrated with the present operation and configuration of the FPC system.

Contracted Firm Capacity Purchases

From Qualifying Facilities in Florida

Figure ES.4



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Table ES.1 summarizes the 10 generation alternatives, which include combinations of large and small pulverized coal units, gas combustion turbines, fluidized bed and orimulsion (low grade Venezuelan crude oil) plants, and additional capacity purchases from existing, low cost units. Each of the alternatives would come into service between 1997 and 2000. The table displays the size, timing, and type of each addition and the total capacity added under the alternative. It also contains a brief summary of the main distinguishing characteristics for each.

Section 8 of the Study describes the economic evaluation of the 10 alternatives. In addition to expected present worth revenue requirements for each alternative, FPC evaluated 27 different uncertainties based on the high, medium, and low demand and energy forecasts; the high, medium, and low fuel forecast; and the high, medium, and low conceptual cost estimates. The final result of this "decision analysis" was an accumulated expected net present value of the total cost of that alternative on FPC's system. Supporting data was also generated for 27 various scenarios which, when accumulated with their probability of occurring, would equal their expected value. Cumulative and annual cost curves were also generated over time to enable revenue requirement cash flow comparisons.

The Polk County combined cycle plant emerged from all of these calculations as the most cost-effective alternative. In other words, these units are expected to lead to the lowest cost of service and the lowest rates, when viewed on a present value or present worth basis. The units also do not pose any unusual risks in the event that some of the key planning assumptions used by FPC turn out to vary according to their expected probability distribution.

THE POLK COUNTY UNITS

The units found to be most cost effective in this Study consist of four 235 MW natural-gas-fired combined cycle generating plants. These generating stations have a number of advantages, including:

Ten Proposed Alternatives

Table ES.1

Alternative	Comments	1997	1998	1999	2000	MW Capacity	Description
1	PC - Large		2CTD-165	PC-700		1030	Economy of scale, secure fuel, long lead time
2	PC - Small		2CTD-165	PC-450	CTD-165	945	Secure fuel, long lead time, base & peak cap.
3	CC - Gas		CCG-235	2CCG-235	CCG-235	940	Gas available, spread capacity to meet reserve margin (RM)
4	CC - Distillate		CCD-235	2CCD-235	CCD-235	940	Gas NOT available, spread capacity to meet RM
5	CT - Gas - Small		6SCTG-40	10SCTG-40	8SCTG-40	960	Gas available, low capital to meet RM
6	OUC Purchase/CC-Gas	OUC-110	CCG-235	2CCG-235	CCG-235	1050	OUC coal purchase, CC & CT on gas
7	IGCC		CTD-165	IGCC-580	IGCC-290	1035	New tech., inexp. fuel, economy of scale, CT for RM
8	Fluidized Bed		CTD-165	3FBC-150	2FBC-150	915	New technology, inexpensive fuel
9	OGCC		OGCC-593		2CTD-165	923	New tech., very inexp. fuel, economy of scale, CT for RM
10	Purchase PC - Small		PU-PC-376	CCG-235	2CTG-165	941	Short lead time, UPS, wheel cost, low capital, CT for RM
LEGEND:						NOTES:	
PC - Pulverized Coal CCG - Combined Cycle on Gas CCD - Combined Cycle on Distillate SCTG - Small Combustion Turbine on Gas CTG - Large Combustion Turbine on Gas CTD - Large Combustion Turbine on Distillate IGCC - Integrated Gasification Combined Cycle on Coal FBC - Fluidized Bed Combustion on Coal OUC - Orlando Utilities Temporary Coal Purchase OGCC - Orimulsion Gasification Combined Cycle PU-PC - Purchase Pulverized Coal - UPS All in-service dates are November 1. # of units precede unit description. Unit Winter MW capacity follows unit description.						Winter MW Capacity used for Reserve Margin shown in table above.	

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- Minimal environmental impacts,
- A large number of proven, reliable vendors,
- Short construction periods, and
- Extremely efficient operation.

The units are projected to cost approximately \$599/KW (1991 Dollars).

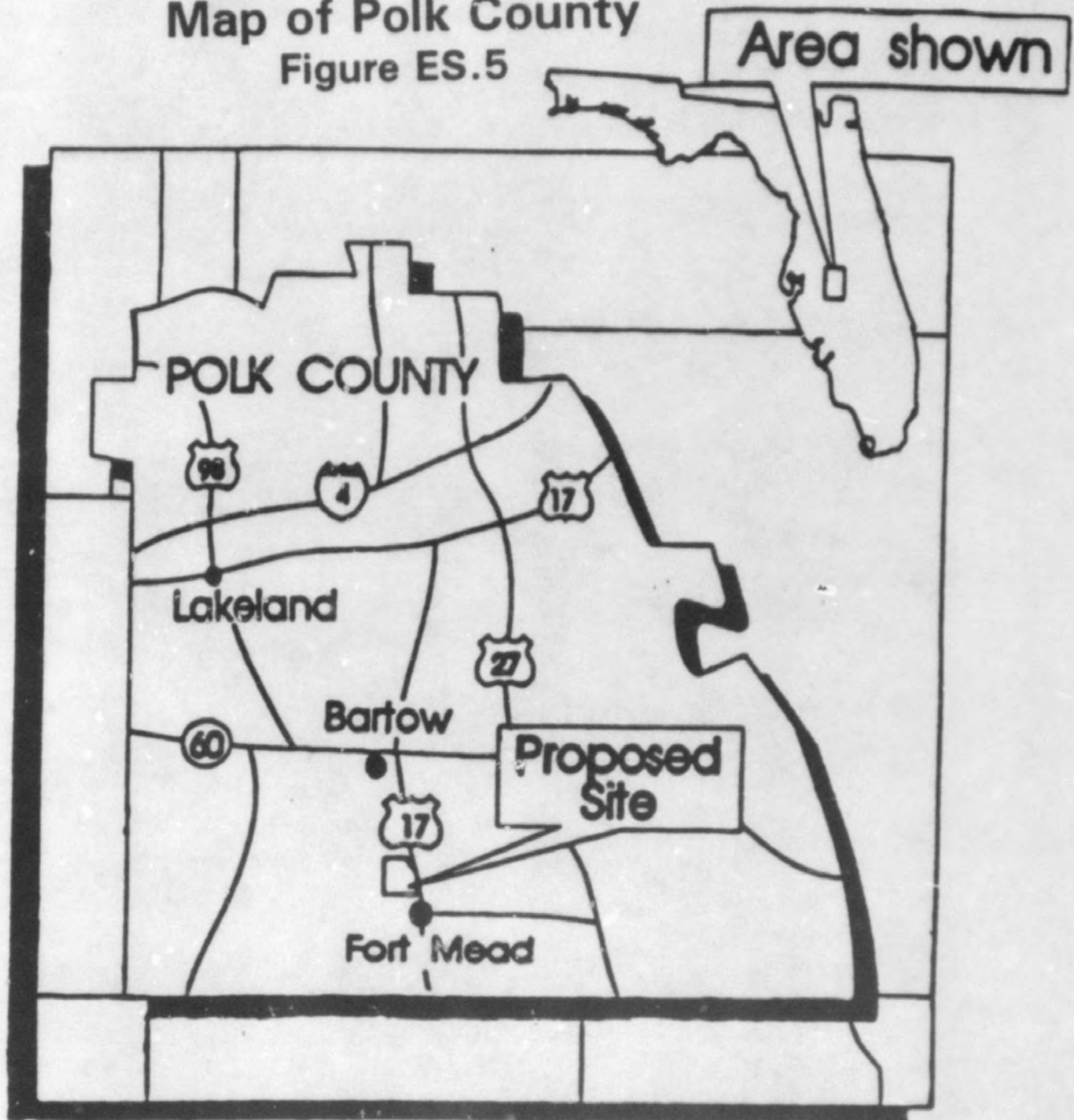
The proposed plants will be sited on a parcel of former phosphate mines in Polk County (see Figure ES.5). This site was chosen based on a lengthy, careful search and in consultation with community and environmental interests. The existing site has ponds and other geographic features that are readily adapted to power plant use. Moreover, the site can accommodate more than 2,000 additional MW of future capacity as well as coal gasification facilities. Finally, the site is centrally located with respect to FPC's load and will require minimal additional transmission construction.

AN EXPANDED STATEWIDE FUEL SUPPLY

One significant advantage of the proposed Polk County plants is their use of natural gas, which is an inexpensive, clean-burning source of energy. To ensure that the Polk County units will have an adequate and reliable fuel supply, FPC analyzed the general availability and price of wellhead natural gas and three particular fuel supply alternatives. The three alternatives were: 1) FPC participation in the construction of a new pipeline through Polk County, 2) construction of a new pipeline by an unaffiliated pipeline company, and 3) an expansion of the Florida Gas Transmission system.

FPC's analysis indicates that all three of these supply alternatives are capable of providing a reliable supply of fuel for the Polk County units. In addition to providing fuel for these plants, the construction of a second pipeline along the western part of the Florida peninsula would provide expanded supply opportunities to communities, industrial plants, utilities, and qualifying facilities.

Map of Polk County
Figure ES.5



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A FINANCIALLY AFFORDABLE CONSTRUCTION PROGRAM

Once FPC had determined that the Polk County units would be the lowest cost generation alternative, it went on to examine the financial aspects of the construction program required to install them. This financial analysis was conducted to ensure that FPC would be able to support this construction without adversely affecting its financial stability, customer service, or electricity prices.

Four areas of FPC's financial plan were analyzed to evaluate the financial viability of the Polk County undertaking. First, key financial ratios were evaluated against internal Florida Power objectives and against well-recognized financial tests applied by credit rating agencies. Second, the viability of the aggregate amount and the timing of necessary new debt and equity issues were verified. Third, the plan was reviewed from the broad perspective of investors who would assess Florida Power, giving primary emphasis to a demonstration of sustainable financial stability and a healthy, stable rate of growth. Fourth, the impact on customer rates resulting from projected activities was measured on both a nominal and real (inflation-adjusted) basis.

FPC's financial analysis indicates that it should have no problem maintaining its credit quality during and after the construction of the Polk units, assuming appropriate and timely regulatory treatment. The ratio of net external financing to total capitalization is projected to remain below 6% on an annual basis for most of the next decade. This is substantially below the 10-16% levels reached during FPC's last major construction cycle, which included construction of the Crystal River 4 and 5 pulverized coal units. Other measures of financial stability, such as the time path of construction expenditures, also point to the financial viability of the construction program.

FPC's analysis also included an evaluation of the financial impact of planned power purchases. While purchased power can be beneficial when used prudently, excessive reliance on external sources of generating capacity adversely impacts a utility's financial condition. In recognition of this fact, the major bond rating agencies include the financial impact of purchased power in the determination of the financial stability and creditworthiness of investor-owned electric utilities.

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FPC has concluded that the amount of power purchases has become a large enough factor in FPC's mix of resources and overall financial posture to have a material effect on FPC's credit rating. It would be financially imprudent for FPC to make more power purchases than are currently planned. FPC's analysis also shows that its long-term financial interests are best served if Florida Power owns, and rate bases, a substantial portion of its future generation needs.

STRATEGIC CONSIDERATIONS

In addition to examining the measurable economic benefits of the Polk County units, FPC examined the role of a number of strategic and policy considerations in strengthening or weakening the case for this particular alternative. These factors included fuel supply/fuel diversity factors, environmental and siting benefits, the impacts of excessive reliance on external purchases, and FPC's procurement approach. In brief, the strategic assessment reached four important conclusions:

- Even after the incorporation of the maximum feasible amount of DSM in FPC's integrated resource plan, additional generation resources are necessary to preserve system reliability.
- Adding to FPC's generation resources by purchasing additional capacity would result in higher costs to customers than if FPC builds the Polk County units. Additional purchases will adversely affect FPC's financial integrity through their impact on credit ratings, long-run financial structure, system flexibility, and other factors.
- Even if Florida Power were to ignore the financial impacts of additional purchases, purchased generation is likely to cost more than the proposed Polk County units.
- The construction of the Polk County units will prompt a substantial expansion of gas pipeline capacity in Peninsular Florida.

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These four factors, together with other considerations, make the Polk County units the best and most cost-effective resource expansion option for Florida Power Corporation in the 1997-2000 time period.

WHY BIDDING IS ILL-ADVISED IN THIS CASE

FPC is aware that several past need cases brought before the Commission have relied on competitive procurements or "bidding" programs to identify the needed generating resource. FPC believes that the facts of *this* case, however, demonstrate that competitive procurement is inappropriate and would unnecessarily delay implementation of Florida Power's integrated resource plan.

The facts supporting FPC's decision not to bid are discussed throughout the Study. Briefly, these include:

- FPC's financial stability and integrity is impaired when its reliance on purchased capacity grows too large;
- FPC's research indicates that QFs will not be able to make credible offers to build the type and the quality of capacity needed by the FPC system more cheaply than FPC can construct that capacity;
- FPC has already conducted one competitive procurement for QF resources and does not need additional resources of this type at the present time;
- FPC is already purchasing as much capacity from QFs as all other Florida utilities combined;
- Proper utility resource plans are diversified and do not rely too heavily on purchases from external sources;

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- Overreliance on purchases diminishes the planning, scheduling, and environmental compliance adaptability of the FPC system;
- Excessive purchases of capacity also diminish the operating and maintenance flexibility of the FPC system; and
- FPC has a superior record of constructing generating units in a highly cost-effective manner by achieving the proper blend of competitive procurement and utility construction management.

FPC believes that certain of the above-stated facts alone provide reason enough to reject the competitive procurement approach. When all of these facts are considered together, it is overwhelmingly clear that the balance, flexibility, and cost effectiveness of FPC's integrated resource plan would be substantially compromised if FPC were forced to rely on bidding to supply its capacity needs.

CONSISTENCY WITH STATEWIDE NEED

Based on data compiled by the Florida Coordinating Group (FCG), FPC has concluded that the proposed Polk County units are consistent with statewide needs. The FCG recently published a compilation of individual utility plans and produced a summary entitled *1991 Ten-Year Plan for the State of Florida*. This plan is a compilation of the most current information and assumptions regarding the load forecasts and the existing and planned generation and bulk transmission facilities for the Florida utilities. The *Ten-Year Plan* indicates that the planned growth in statewide generation resources, including new FPC generating units as well as all planned QF and utility purchases, is consistent with the projected growth in firm peak demand across the state.

EXECUTIVE SUMMARY

THE CONSEQUENCES OF DELAY

The four proposed Polk County units are sized and scheduled so as to meet FPC's dual reliability criteria of 0.1 days per year LOLP and 15% winter reserve margin. Any delay that affects the in-service date of these units must be evaluated against its effect on these criteria, as well as a consideration of what alternatives are available to FPC.

A one-year delay in the in-service date of each of the proposed units will cause FPC's winter reserve margin to drop below its minimum level of 15% in each year. Table ES.2 shows that with a one-year delay, the reserve margins will range from a low of 12% in the winter of 1999/2000 to 14.5% the following winter. Further delays will have a more dramatic effect.

The drop in reserve margin puts FPC's customers at risk because there may be insufficient generation to meet their demands. While FPC would be forced to search for alternatives to meet its customers demand in any case, this Study shows that the Polk County combined cycle units are the most cost-effective alternative reasonably available to meet FPC's needs in this time frame. These units have been proposed only after FPC took into account all other reasonably available and cost-effective alternatives. A delay in the licensing or construction of the Polk County units represents a threat to the safety and economic well-being of the FPC service area and the state as a whole.

CONCLUSION

This integrated resource study has described the basis for FPC's determination that the proposed Polk County units are the most cost-effective means of providing reliable service during the latter part of the 1990s. Based on a comprehensive supply- and demand-side analysis, these four 235 MW, natural-gas-fired combined cycle units have been found to be a necessary, efficient, economical, and environmentally sensitive addition to FPC's integrated system. These high efficiency units utilize a reliable, environmentally compatible generating

Impact of Delaying Construction on Polk County Units
Table ES.2

SEASON	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	FIRM * PEAK DEMAND (MW)	FIRM RESERVES	
						(MW)	(%)
Winter 1990/1991	6,571	400	112	7,083	5,834	1,249	21.4%
Summer 1991	6,192	400	135	6,727	5,559	1,168	21.0%
Winter 1991/1992	6,621	400	168	7,189	6,681	508	7.6%
Summer 1992	6,207	400	168	6,775	5,809	966	16.6%
Winter 1992/1993	6,985	400	203	7,588	6,921	667	9.6%
Summer 1993	6,511	400	356	7,267	6,046	1,221	20.2%
Winter 1993/1994	7,389	400	590	8,379	7,047	1,332	18.9%
Summer 1994	6,855	400	590	7,845	6,223	1,622	26.1%
Winter 1994/1995	7,389	400	624	8,413	7,172	1,241	17.3%
Summer 1995	6,855	400	624	7,879	6,418	1,461	22.8%
Winter 1995/1996	7,389	400	769	8,558	7,300	1,258	17.2%
Summer 1996	6,855	400	769	8,024	6,575	1,449	22.0%
Winter 1996/1997	7,389	400	769	8,558	7,422	1,136	15.3%
Summer 1997	6,855	400	769	8,024	6,727	1,297	19.3%
Winter 1997/1998	7,389	400	919	8,708	7,536	1,172	15.5%
Summer 1998	6,855	400	919	8,174	6,873	1,301	18.9%
Winter 1998/1999	7,389	400	919	8,708	7,647	1,061	13.9%
Summer 1999	6,855	400	919	8,174	7,019	1,155	16.4%
Winter 1999/2000	7,375	400	919	8,694	7,762	932	12.0%
Summer 2000	6,826	400	919	8,145	7,188	957	13.3%
Winter 2000/2001	7,785	400	919	9,104	7,950	1,154	14.5%
Summer 2001	7,176	400	919	8,495	7,365	1,130	15.3%

* Firm peak demand is forecasted demand less interruptible load.

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technology and are projected to enter service in 1998, 1999 (two units,) and 2000. At an estimated cost of \$599/KW (excluding AFUDC), these plants are significantly less costly to the FPC system than all other available generation alternatives, including purchases from other utilities or non-utility generators.

Figure ES.6 illustrates the balanced approach FPC has taken in its integrated resource plan. The graph shows that FPC will remain heavily reliant on demand-side management and outside purchases to meet its customers requirements and maintain adequate reserves.

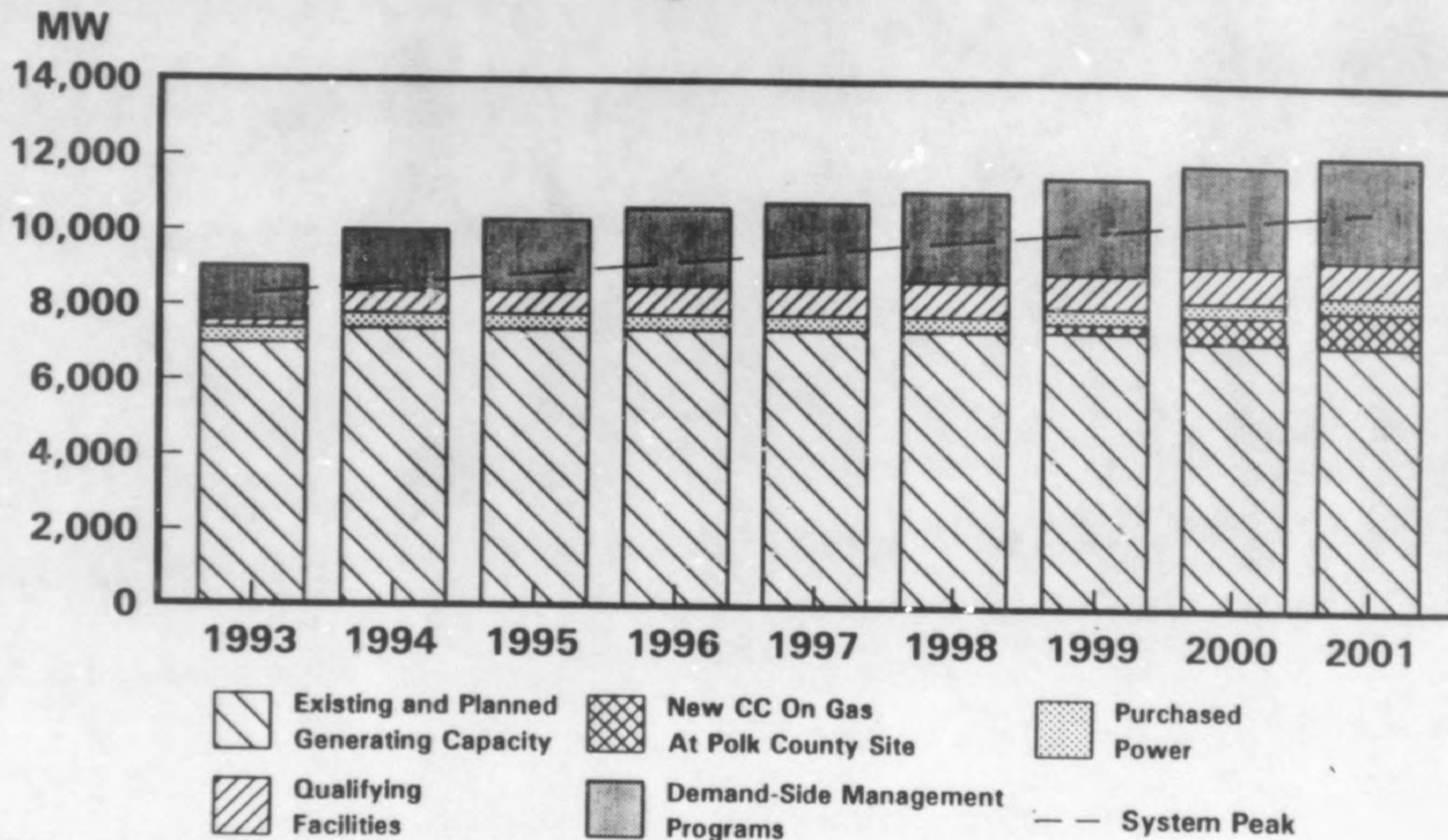
The Polk County units also will play a key role in bringing new natural gas transportation capacity to the state of Florida. These units, together with the planned conversion of existing generation, will allow FPC to make a substantial gas usage commitment. New pipeline capacity is economically feasible only when this sort of large scale commitment can be made. With the addition of the Polk County units, the fraction of FPC generation produced from natural gas will increase from near zero to almost 15% by the year 2001.

In sum, FPC's integrated resource plan, including the Polk County units, represents a cost-effective means of meeting the energy service needs of the customers of Florida Power Corporation. The Polk County units are also consistent with the statewide need to build additional generating capacity to serve Florida's electrical energy needs well into the 21st century.

Total Resources And Native Winter Peak Demand

1993 - 2001

Figure ES.6



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Section 1: INTRODUCTION

PURPOSE

This document describes the integrated resource planning (IRP) process that has led the Florida Power Corporation (FPC, or "Florida Power") to petition the Florida Public Service Commission ("the Commission") for permission to construct four natural-gas-fired combined cycle generating units in Polk County during the years 1998-2000. This integrated resource study ("Study") demonstrates that Florida Power will require additional generating resources over and above all other economical and reliable alternatives available to meet its customers' load growth in the years following 1997.

FPC's use of integrated resource planning has led to development of a balanced, cost-effective portfolio of resources with which to supply its customers' needs. The integrated resource plan, which includes the proposed Polk County plants, first makes aggressive use of the demand-side management (DSM) resources inherent in FPC's service area. The plan further diversifies the resource portfolio by placing a significant reliance on capacity and energy from cogeneration facilities, out-of-state purchases, and the installation of new transmission resources. The proposed generating units are a complement to this resource portfolio and produce a balanced, cost-effective plan that simultaneously preserves system reliability, environmental integrity, low cost services, and the financial security of Florida Power. The plants requested in this determination of need and the other components of the portfolio will enable FPC to remain a low cost electric supplier in Peninsular Florida well into the 21st century.

This past spring, in the Commission's Annual Planning Hearing in Docket No. 910004-EU, FPC explained the preliminary results of its new integrated resource plan. Since that time, FPC has worked to improve its planning process and to finalize its planning studies. The plan presented in this document is consistent with, and a more complete exposition of, the plan described in the Annual Planning Hearing.

INTRODUCTION

FPC'S APPROACH TO INTEGRATED RESOURCE PLANNING

FPC employs an approach to IRP known in the industry as "DSM first." That is, forecasted economic conditions and DSM costs are used to develop a set of DSM programs that are cost effective for customers under the forecasted conditions. As new technologies and markets develop, it is expected that the mix of programs will continue to evolve. The capacity savings resulting from these programs — a projected 1,400 megawatts (MW) by the year 2000 — is subtracted from the forecast of FPC system peak load.

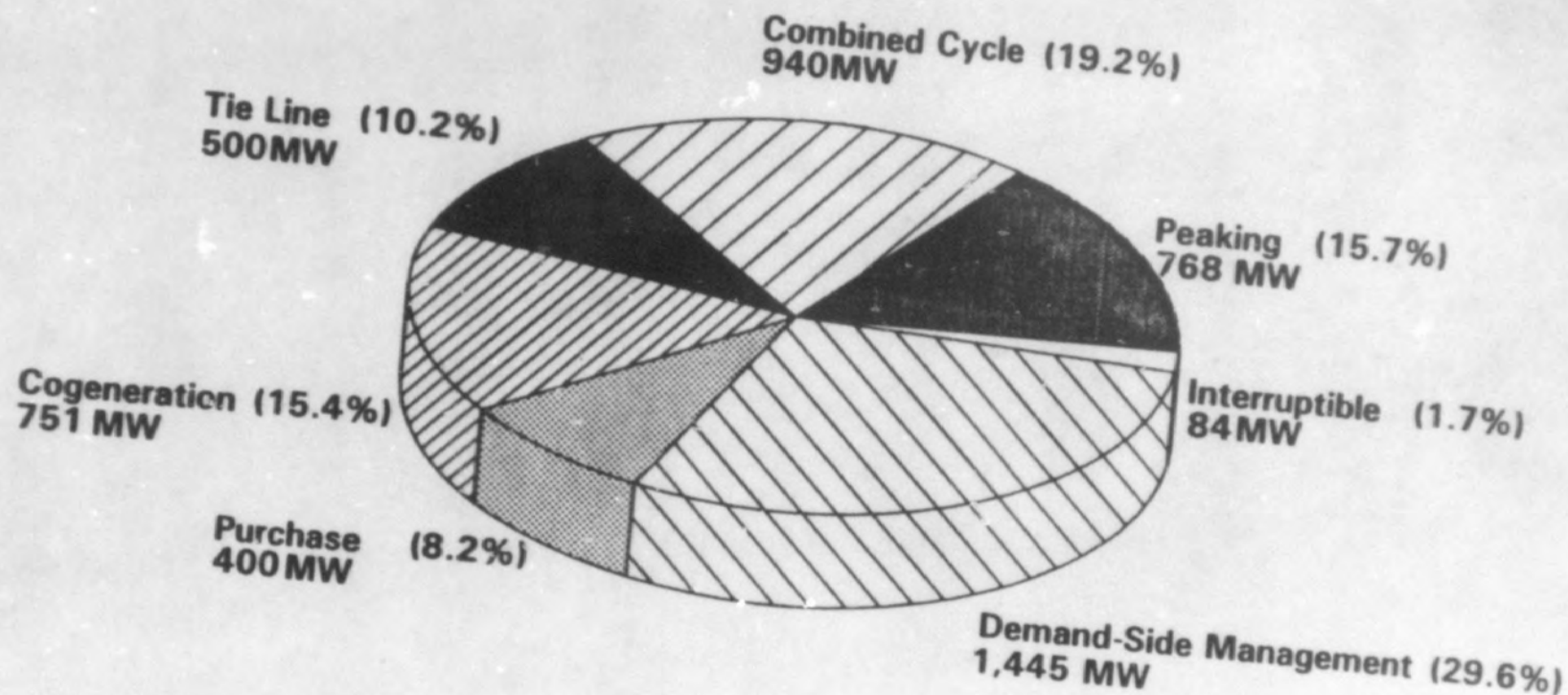
If this process results in no need for additional generating plant, the IRP process concludes with DSM program design and implementation. However, where load growth exceeds what can reasonably be achieved with aggressive DSM, additional generation is required. In these instances, the IRP process leads to the design of a generation expansion plan that is most cost effective in light of planned DSM and other activities and assumptions. Figure 1.1 displays the projected mixture of additional capacity sources in FPC's integrated resource plan.

The first sections of this Study describe the economic assumptions, load forecast, and DSM program implementation. When FPC's Maximum Avoidable Capacity Scenario ("M.A.C.S.") DSM is subtracted from forecast load, there remains a need for additional generation in order to preserve FPC's reliability standards for service to its customers. The second half of the Study describes a comprehensive generation expansion planning process that resulted in the selection of the Polk County units as the most cost effective.

TIME HORIZON OF THE INTEGRATED PLAN

The integrated resource planning exercise described in this document focused on the reliability of FPC service and the need for new resources starting in 1992. Some of FPC's resource additions through the year 1997 are either planned or committed, and they form the baseline for the analysis of additional needs. The primary focus of the Study was the evaluation of resource additions from 1997 through 2000.

**Total Additional Resources (4,888 MW)
To Meet 2001 Winter Peak Demand**
Figure 1.1



Base Year 1992
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INTRODUCTION

The study focuses on the ten years following the year in which the study was conducted, i.e., the period from 1992 through 2001. FPC recognizes that it is necessary to take into account the inevitably arbitrary nature of the cutoff date in an IRP study. The Polk County units that are the result of this Study are in part a recognition of the need to incorporate flexibility into the plan and to provide for a smooth transition to post-2001 resource additions. For example, FPC's strategy for complying with the revised Clean Air Act makes it imperative that generation resources constructed in the late 1990s assist with clean air compliance in the following decades.

MAJOR COMPONENTS OF FPC'S INTEGRATED PLANNING PROCESS

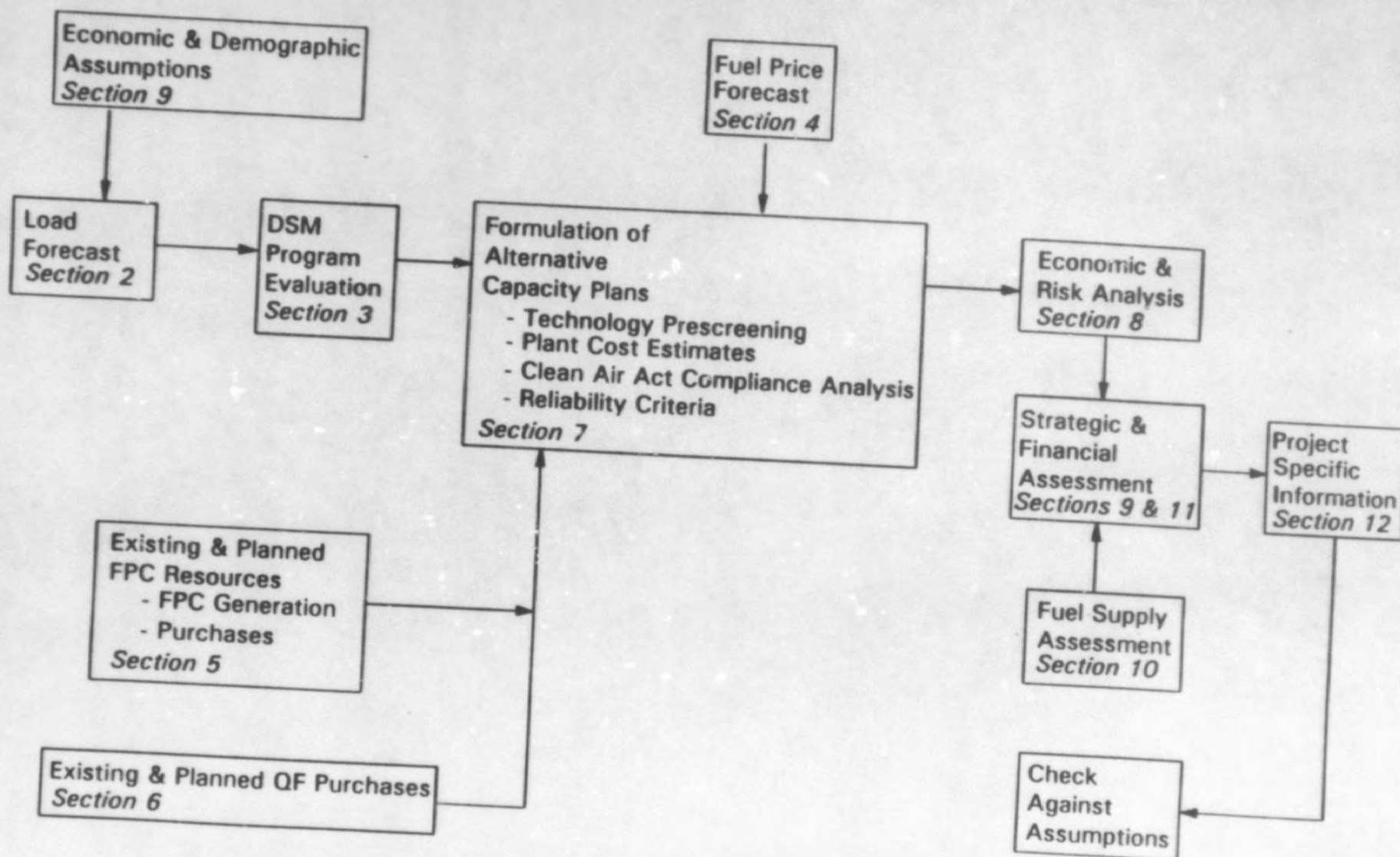
An overview of Florida Power's integrated resource planning process is shown diagrammatically in Figure 1.2. Integrated resource plans are produced via large analytical efforts evaluating and reviewing all feasible, cost-effective means of meeting the needs of utility customers. FPC's implementation of this planning concept has been carried out in a series of activities and analyses shown in Figure 1.2. To assist the reader in following this process through the remainder of the study, Figure 1.2 shows the section of the study that describes the corresponding step in FPC's IRP process.

The first step in the IRP process was the development of economic, financial, and other assumptions that were used throughout the Study. In addition to serving as key inputs to formal load forecasting models, these variables underlie most of the economic calculations used in the Study.

As Figure 1.2 demonstrates, the economic/demographic assumptions are an immediate input to the load forecasting process. The specific forecast employed in this study is described in Section 2.

FPC's Integrated Resource Study

Figure 1.2



INTRODUCTION

Following the completion of the load forecast, the DSM-first method of IRP calls for the development of the maximum feasible DSM programs. The development of FPC's M.A.C.S. case involves numerous elements, including technology assessment, market acceptance considerations, cost-effectiveness evaluation, psychodemographic analysis, the effect of existing market saturations, DSM experience at other utilities in Florida and other states, Florida Power staff and field experience, human resource planning, and numerous other elements. It is important to recognize the dynamic nature of the M.A.C.S. case programs. It is structured such that program effects are regularly evaluated, and emerging markets and technologies are continually assessed in order to augment or vary the existing roster of programs.

FPC's work in developing and implementing the M.A.C.S. case is described in detail in Section 3. The amount of DSM found to be feasible and economical is introduced back into the load forecast to reflect the anticipated reductions that demand-side management will have on load growth. Section 4 details the fuel price forecast developed by FPC as one of the basic inputs to the planning process.

The identification of a reliability shortfall following projected DSM implementation begins the process of developing a cost-effective generation expansion plan. FPC next examines the existing and planned generation projects on its system. Future construction to which FPC is committed is included in this resource "baseline," as are contracted purchases from other utilities and Qualifying Facilities (QFs). The purchases included in the baseline are *in addition* to those evaluated as candidate expansion plans, and they do not depend on the findings of this IRP study. The evaluation of existing and planned generation and transmission resources is described in Section 5. The existing and planned QF purchases are described in Section 6.

The next step in the planning process is the formulation of a comprehensive set of alternatives for detailed economic and strategic evaluation. This step incorporates four major considerations. First, the technologies used in alternative plans must meet FPC's criteria for technical feasibility, reliability, and potential cost effectiveness. Second, the alternative plans must result in a system that meets or exceeds FPC's reliability criteria during each year of the plan. Third, the alternative plan must be consistent with FPC's commitment to

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environmental protection, and in particular must permit Florida Power to comply with the revised Clean Air Act limitations on sulfur dioxide emissions. Finally, the alternative must represent a plan that is well integrated with the present configuration and operation of the FPC system. Section 7 describes the application of these considerations to the development of ten alternative generation expansion plans.

In Section 8, the evaluation of each of these plans using a decision analysis framework is described. In addition to computed average present worth revenue requirements for the alternative plans, FPC evaluated 27 different uncertainties based on the high, medium, and low demand and energy forecasts; the high, medium, and low fuel forecast; and the high, medium, and low conceptual cost estimates. The final result of this decision analysis was an accumulated expected net present value of the total cost of that alternative on FPC's system. Supporting data was also generated for 27 various scenarios which, when accumulated with their probability of occurring, would equal their expected value. Cumulative and annual cost curves were also generated over time to enable revenue requirement cash flow comparisons.

The construction of the four Polk County natural-gas-fired combined cycle plants emerged from all of these calculations as the most cost-effective alternative. However, this finding alone was not sufficient to complete the integrated resource planning process. The additional steps may be summarized as follows:

- First, Florida Power examined the financial feasibility of the least-cost option to insure that the Polk County units could be constructed without harming FPC's financial creditworthiness and stability. This analysis indicated that the Polk County units could be financed without impairing FPC's financial integrity. The analysis also suggested that excessive reliance on purchased power would negatively impact FPC's financial condition. This is discussed in Sections 9 and 11.
- Second, a fuel supply assessment was made to insure that the Polk County plants could obtain a reliable supply of fuel at prices consistent with the fuel price forecasts. This analysis is explained in Section 10.

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- Florida Power also examined the Polk County units from a number of strategic and policy directions. Among the considerations examined was the proper extent of FPC's reliance on purchased capacity and whether purchased capacity should be procured using a bidding system. FPC's inquiry into these matters, described in Section 11, concluded that overreliance on purchases would produce an unbalanced resource portfolio and undermine FPC's operating flexibility and financial security. In view of its estimated cost for the Polk County units, its exemplary construction record, and its approach to construction management, FPC does not believe that additional procurement of firm capacity from outside sources is in the interests of its customers and shareholders at this juncture.
- Next, FPC developed more complete design, cost, scheduling, and siting information for the Polk County units. This project-specific information is described in Section 12.
- Florida Power studied the consistency of its plan with statewide needs. Section 13 examines this issue.
- Finally, Section 14 discusses the consequences of further delay.

WHY BIDDING IS ILL-ADVISED IN THIS CASE

FPC is aware that several past need cases brought before this Commission have relied on competitive procurements or "bidding" programs to identify the needed generating resource. FPC believes that the facts of *this* case, however, demonstrate that competitive procurement is inappropriate and would unnecessarily delay implementation of Florida Power's integrated resource plan.

The facts supporting FPC's decision not to bid are discussed throughout the Study. Briefly, these facts include:

- FPC's financial stability and integrity are impaired when its reliance on purchased capacity grows too large;

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- FPC's research indicates that QFs will not be able to make credible offers to build the type and the quality of capacity needed by the FPC system more cheaply than FPC can construct that capacity;
- FPC has already conducted one competitive procurement for QF resources and does not need additional resources of this type at the present time;
- FPC is already purchasing more capacity from QFs than all other Florida utilities combined;
- Proper utility resource plans are diversified and do not rely too heavily on purchases from external sources;
- Overreliance on purchases diminishes the planning, scheduling, and environmental compliance adaptability of the FPC system;
- Excessive purchases of capacity also diminish the operating and maintenance flexibility of the FPC system; and
- FPC has a superior record of constructing generating units in a highly cost-effective manner by achieving the proper blend of competitive procurement and utility construction management.

FPC believes that certain of the above-stated facts, by themselves, provide reason enough to reject the competitive procurement approach. When all of these facts are considered together, it is overwhelmingly clear that the balance, flexibility, and cost effectiveness of FPC's integrated resource plan would be substantially compromised if FPC were forced to rely on bidding to supply its capacity needs.

Section 2: LOAD FORECAST

INTRODUCTION

This section presents Florida Power Corporation's forecast methodology and results. FPC's long-term forecasts of customers, energy sales, and seasonal peak demands constitute important inputs to the integrated resource planning process. FPC's forecasts are reported on an annual basis over a 20-year forecast horizon, in this case the period 1991 through 2010. Seasonal peak demands are reported on a total system basis, while the forecasts of customers and sales are disaggregated by revenue classification.

The forecast used in this study is called a "long-term forecast" because it attempts to capture the long-term trend in FPC's customers, energy sales, and peak demand over the next 20 years. As a result, the forecast does not consider or attempt to project economic business cycles beyond the first few years of the forecast. Rather, it identifies a trend that would cut through the middle of any future business cycle fluctuations.

FORECAST METHODOLOGY

FPC develops its long-run 20-year forecasts of customers, energy sales, and peak demand via a forecasting system that includes several statistical models. These models incorporate forecasting techniques ranging from simple time-series and regression analysis to more sophisticated and highly detailed end-use models. Based on historical data, statistical trends and relationships between relevant variables are developed and analyzed. Population, weather, economic conditions, and the price of electricity are examples of some of the variables used in these models.

LOAD FORECAST

Forecast Assumptions

All elements of FPC's forecast are based on a set of assumptions produced by the Load Forecasting Section of the Business Planning Department. These assumptions are developed through coordinated discussions with other departments at FPC and from forecast information available from external sources such as customer contacts and public and private research organizations. The forecast assumptions represent general statements concerning important factors affecting the customer, energy sales, and peak demand forecast. The assumptions also provide relevant information concerning the anticipated outlook for Florida's economy as well as several major sales categories, including the phosphate industry and sales for resale. Appendix A provides a summary of the assumptions used in this forecast, as well as additional detail concerning FPC's forecasting system inputs and results.

Customers

Population within the 32 counties spanning the FPC service area serves as the driver for the long-term forecast of residential and commercial customers, which comprise 99% of total system customers. An increasing service area population translates directly into a greater number of households requiring electricity and, consequently, into a greater number of commercial establishments to serve these households.

The Bureau of Economic and Business Research (BEBR) at the University of Florida is the source of population estimates and projections for the FPC 32-county service area. The BEBR "medium-case" population projections provide the basis for the long-term customer forecast. During the course of the 1980s, Florida experienced a population boom in conjunction with a national economy that was rolling through the longest peacetime expansionary period on record. As a result, the BEBR's medium-case projections have generally understated population counts in the state and in FPC's 32-county service area. This consistent underprojection also is evident in the steady increase of the BEBR's medium-case population projections during the past decade. In an effort to acknowledge and account for the historically conservative nature of the BEBR population projections, a slight upward adjustment (approximately 2% by the year 2010) is applied to the long-term customer forecast.

LOAD FORECAST

The remainder of FPC's customers are in the industrial and miscellaneous customer classes. The industrial and miscellaneous sector customers are forecasted through time-series models since they exhibit relatively stable historical trends and account for only 1% of total system customers. Figure 2.1 displays the historical and projected number of total FPC system customers between 1975 and 2010.

Energy Sales

The next component of FPC's forecast is energy (i.e., kilowatt-hour) sales. Residential long-term energy sales are forecasted using SHAPES-PC, an "end-use" computer model developed by the Battelle Columbus Division. In the SHAPES-PC model, the customer forecast is combined with projections of various economic parameters, end-use consumption estimates, and patterns of electricity usage to produce projections of annual energy consumption.

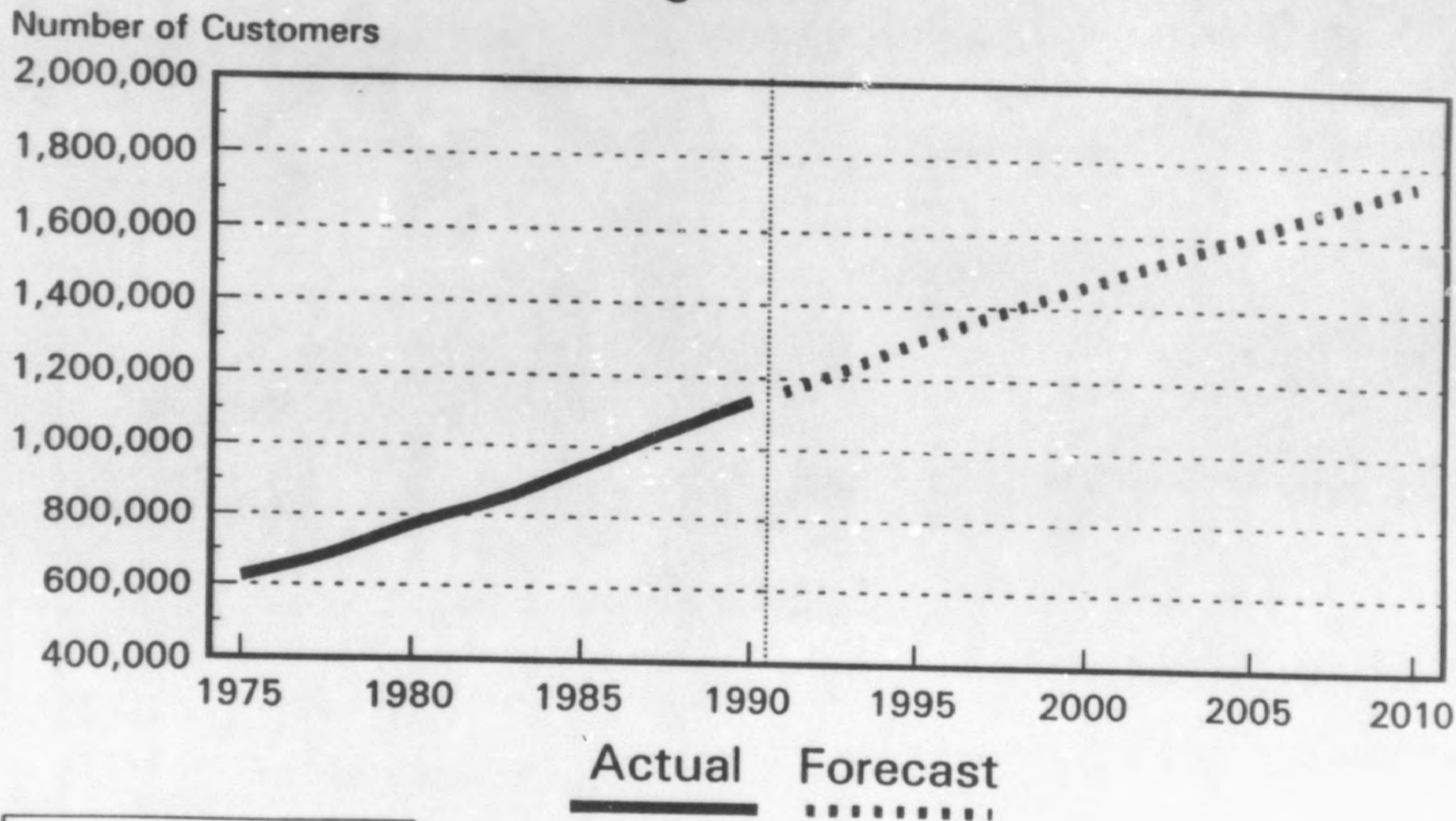
The basic concept underlying the model's structure is that all electrical energy is used to perform a specific function through the operation of various electrical appliances, also known as "end uses." For example, electricity may be used for cooking from an electric range or microwave oven. Heating and cooling may utilize an electric heater, air conditioner, or heat pump. Electricity serves many functions for which there are many types of appliances. Each of these appliance types represent an end use, and the energy consumption of each end use is forecasted separately in the SHAPES-PC model. When all of the energy requirements for the various end uses of residential customers are added together and adjusted to account for FPC's energy conservation program reductions, the result is a forecast of total residential energy consumption.

The industrial sector forecasting model is designed to project energy consumption levels associated with the manufacturing industries and phosphate mining. The major driving forces affecting energy consumption in this model are the real price of electricity, the level of economic activity in the service area, and the technologies or processes of the industries involved. Since energy requirements for a given measure of economic activity vary from one industry to another, the model disaggregates the industrial sector into 12 two-digit Standard Industrial Code (SIC) categories and captures changes in energy consumption due

Total System Customers

April 1991 Forecast

Figure 2.1



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LOAD FORECAST

to changes in the industrial mix. The annual energy consumption in any one of the 12 industries is calculated by multiplying the projected level of economic activity (expressed in employment) by the projected energy intensity (expressed as kilowatt hours per employee).

In the phosphate industry, the results of the forecasting models are supplemented with projections of mining activity based on discussions with FPC's phosphate customers. Furthermore, the industrial sales forecast is adjusted to account for the effects of FPC's energy conservation program impacts and the impact of self-service cogeneration. The self-service cogeneration impact represents a forecast reduction to account for any cogeneration used to supply the cogenerators' own energy and demand requirements, which otherwise would have been served by FPC.

In the commercial sector model, the level of economic activity represents the primary driving variable and is measured directly in terms of employment. Commercial energy intensity per employee is determined, to a large extent, by the real price of electricity and weather conditions. Annual energy consumption in the commercial class is then computed as the projected energy intensity per employee multiplied by the forecast of commercial employment. Like the residential and industrial classes, FPC's energy conservation program reductions are applied to the commercial energy forecast.

Other retail service forecasts are performed for the street and highway lighting and public authority classes. Both are tied to growth in the service area's population base. The street and highway lighting forecast is adjusted to reflect reductions due to luminaire changeouts, an FPC energy conservation program. Forecasts are also performed for two wholesale customer classes. The first category is the Rural Electric Authority revenue class, which consists of one partial requirements customer, Seminole Electric Cooperative Incorporated (SECI). SECI provides FPC with a forecast of its energy requirements above those it expects to supply itself. The second category, the municipal revenue class, includes a number of customer types that are divergent not only in scope of service, i.e., full or partial requirements, but also in the composition of ultimate consumers. Each municipal category, full requirements, partial requirements, and special contract service is forecast separately in order to accurately reflect its individual usage profiles.

LOAD FORECAST

Peak Demand

The seasonal peak demand forecast uses a technique that begins with the separation of winter and summer system peak demand into four major components. These components consist of firm retail load, energy conservation programs, wholesale demand, and interruptible load.

Firm retail load projections are driven by total system customers and coincident weather conditions. Energy conservation estimates are provided by FPC's Customer and Energy Management Services Department, and they reflect all approved energy conservation programs. Wholesale demand projections represent load supplied by FPC to other electric utilities such as SECI, Florida Municipal Power Authority (FMPPA), and miscellaneous municipalities, and they are generally based on information provided by these utilities. The interruptible load component is developed based on historical trends in addition to information obtained through FPC's district representatives. Total system peak demand is then calculated as the algebraic sum of these four components.

Sensitivity Studies

At FPC, the forecasting process includes the development of high and low sensitivity cases for both the energy sales forecast and the winter and summer peak demand forecasts. The primary purpose of the high and low sensitivity cases is to acknowledge and account for the uncertainties inherent in any load forecast. The cases are designed to reflect an approximate 75% confidence interval bandwidth, such that there exists a 75% probability that FPC's future energy and demand requirements will fall somewhere between the high and low cases. Implicit in this analysis is the existence of a 25% probability that future energy and demand requirements will fall somewhere outside of the range between the high and low cases, either above the high case or below the low case.

LOAD FORECAST

FORECAST RESULTS

FPC's customer base is expected to increase over the next 20 years as incoming population migration remains the primary source of customer growth. A compound average annual growth rate of 2.17% per year is anticipated over the 1991-2010 forecast period, as compared to the 3.93% growth experienced during the past 10 years. As shown in Figure 2.1, at this rate of growth, FPC's total number of customers will increase from about 1.14 million in 1990 to almost 1.47 million by the year 2000.

FPC's projected reduction in the rate of customer growth does not necessarily mean a reduction in absolute customer growth. To demonstrate this, Table 2.1 displays the growth rates and number of customers added on the FPC system during the period 1971-2000. The table shows that absolute growth is projected to average 33,615 customers per year during the 1991-2000 time frame, as compared to an annual average of 33,280 for the 1971-1980 period. This is despite the fact that the rate of growth during the 1991-2000 forecast period averages only 2.6% per year, or less than half of the 5.6% annual rate experienced during the 1970s.

Figures 2.2 and 2.3 display projected average electricity use per customer in the FPC area for the residential and commercial customer classes, respectively. Figure 2.2 shows that residential use per customer did not grow smoothly during the late 1970s and early 1980s. Since then, however, per customer usage has grown smoothly and rapidly. This reflects a greater number of large, more energy intensive single family homes in FPC's service area, a trend that is expected to moderate but continue well into the 21st century.

As shown in Figure 2.3, commercial electricity use per customer also did not rise steadily until the early 1980s. While the decline in per customer energy use during the 1979-1980 period was due to a reclassification of customers, the important trend to note in Figure 2.3 is the large, steady rise in the average commercial customers energy consumption since 1983. As in the residential sector, this increased usage has been driven by larger amounts of commercial activities and many new, energy intensive commercial structures.

Absolute and Percent Customer Growth
For Florida Power Corporation
Table 2.1

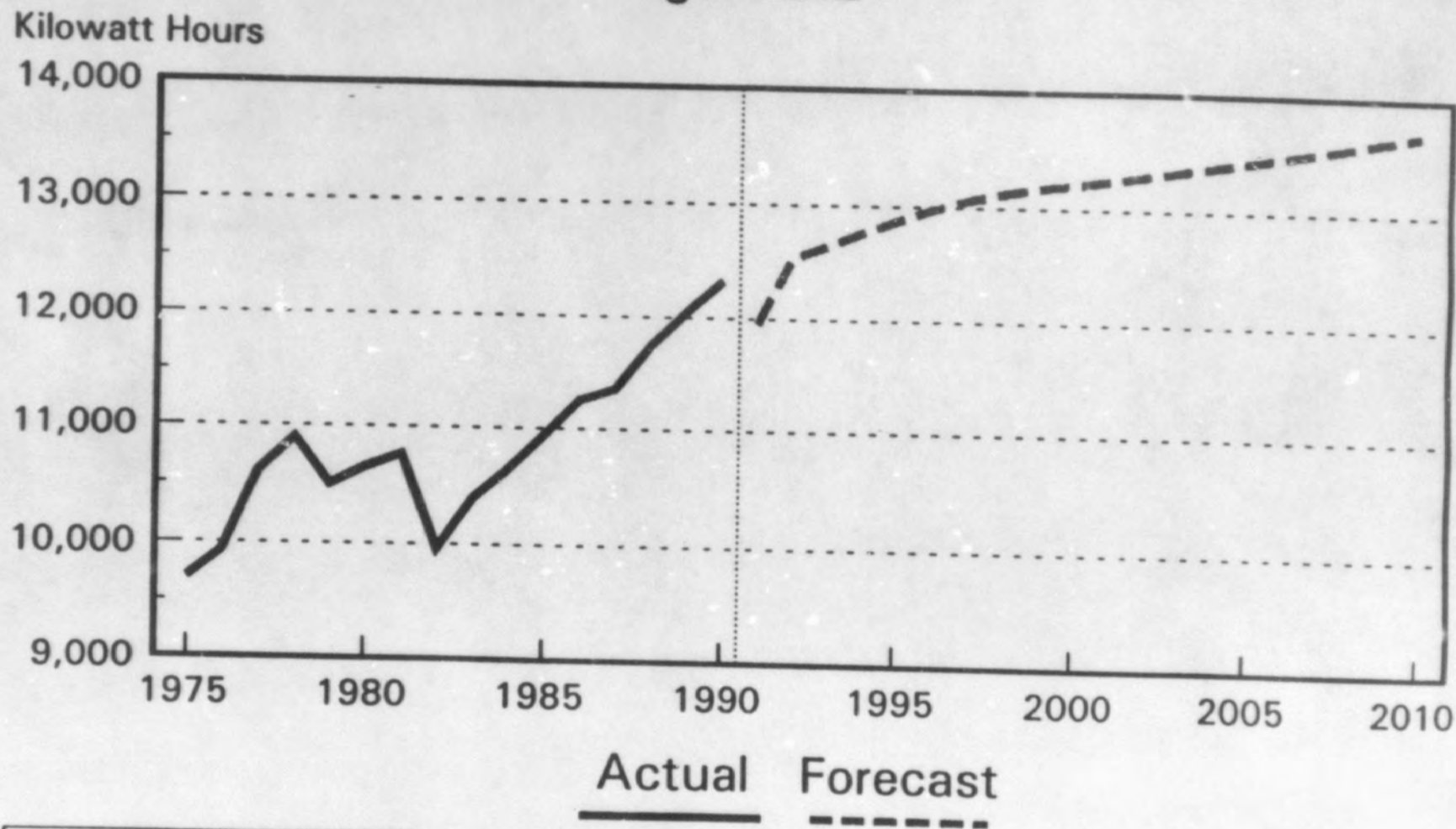
CAG*	Year	Total Customers	Customer Growth	
			Absolute	Percent
	1971	472,743	NA	NA
	1972	515,312	42,569	9.00%
	1973	566,935	51,623	10.02%
	1974	605,332	38,397	6.77%
	1975	621,780	16,448	2.72%
	1976	644,846	23,066	3.71%
	1977	669,615	24,769	3.84%
	1978	699,677	30,062	4.49%
	1979	735,633	35,956	5.14%
	1980	772,265	36,632	4.98%
1971-1980 CAG			33,280	5.60%
	1981	802,787	30,522	3.95%
	1982	829,810	27,023	3.37%
	1983	861,548	31,738	3.82%
	1984	900,799	39,251	4.56%
	1985	940,976	40,177	4.46%
	1986	980,427	39,451	4.19%
	1987	1,023,222	42,795	4.36%
	1988	1,060,971	37,749	3.69%
	1989	1,101,818	40,847	3.85%
	1990	1,135,499	33,681	3.06%
1981-1990 CAG			36,968	3.93%
	1991	1,162,648	27,149	2.39%
	1992	1,193,768	31,120	2.68%
	1993	1,230,075	36,307	3.04%
	1994	1,267,368	37,293	3.03%
	1995	1,303,296	35,928	2.83%
	1996	1,337,785	34,489	2.65%
	1997	1,371,025	33,240	2.48%
	1998	1,403,251	32,226	2.35%
	1999	1,434,594	31,343	2.23%
	2000	1,465,187	30,593	2.13%
1991-2000 CAG			33,615	2.60%
	2001	1,495,152	29,965	2.05%
	2002	1,524,574	29,422	1.97%
	2003	1,553,527	28,953	1.90%
	2004	1,582,088	28,561	1.84%
	2005	1,610,330	28,242	1.79%
	2006	1,638,276	27,946	1.74%
	2007	1,665,948	27,672	1.69%
	2008	1,693,369	27,421	1.65%
	2009	1,720,550	27,181	1.61%
	2010	1,747,503	26,953	1.57%
2001-2010 CAG			28,039	1.75%
1991-2010 CAG			30,782	2.17%

* Compounded Average Growth

Residential Energy Use per Customer

April 1991 Forecast

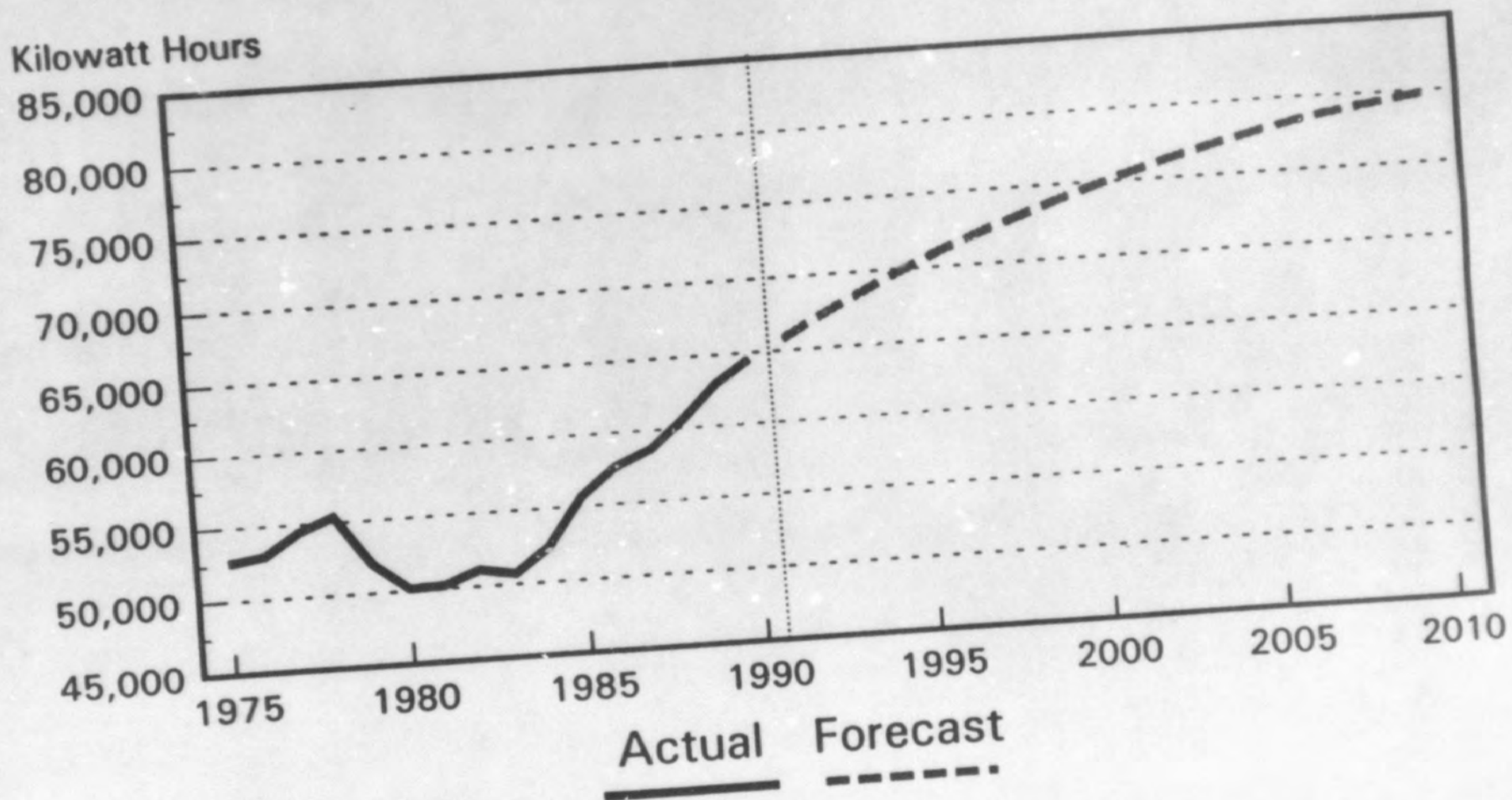
Figure 2.2



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Commercial Energy Use per Customer

April 1991 Forecast
Figure 2.3



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LOAD FORECAST

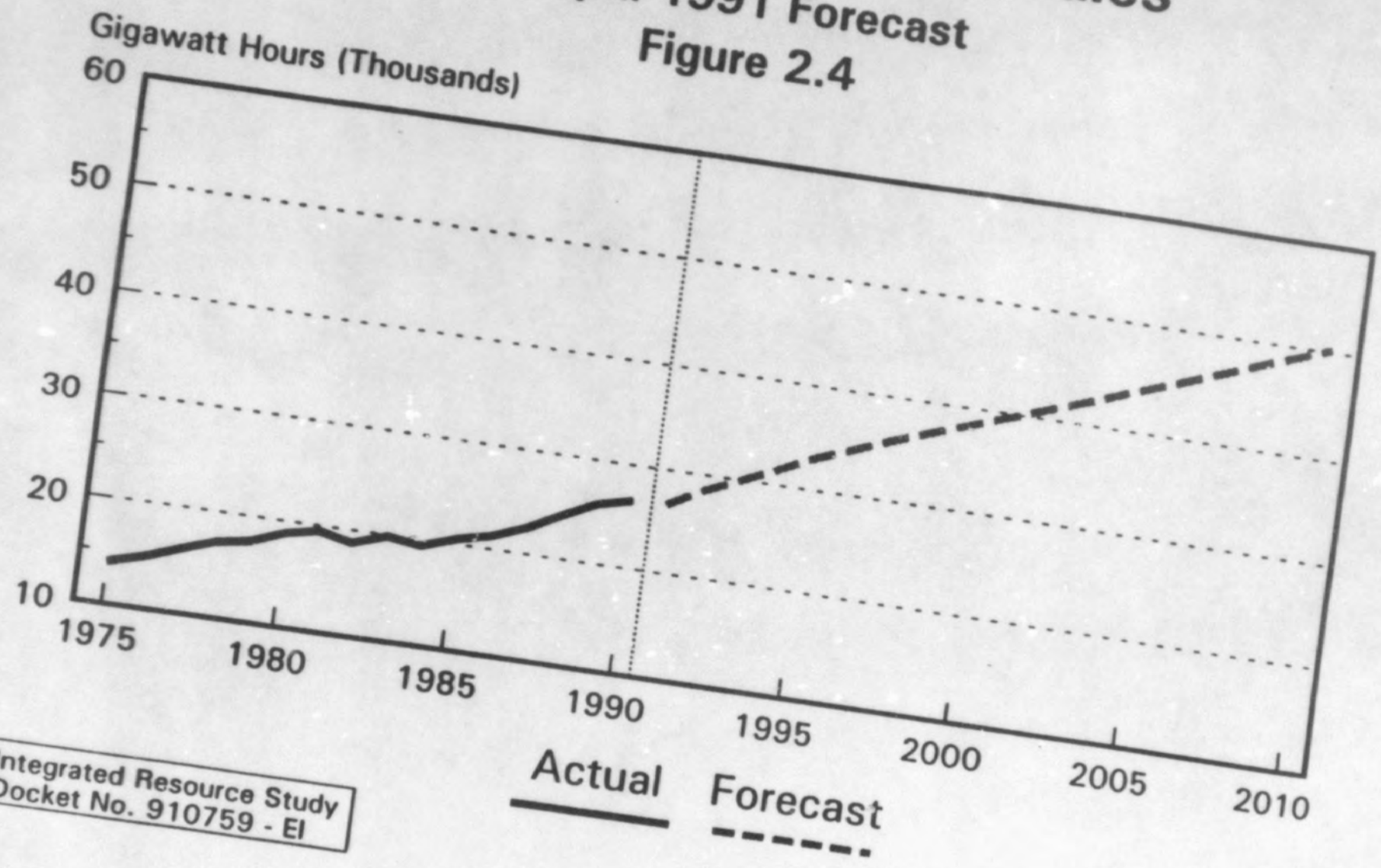
FPC's forecast of total system energy sales shows the combined effects of customer growth and increased average energy use among residential and commercial customers. As shown in Figure 2.4, total energy sales are projected to grow at a rate of 3.41% per year through 2010, compared to a rate of 3.46% per year during the last decade (1980-1990). Winter and summer peak demands, shown in Figures 2.5 and 2.6, are projected to increase at compound average annual growth rates of 2.15% and 2.55%, respectively, over the forecast period. In comparison, the average annual growth rate in winter peak demand during the historical 1979/1980 - 1990/1991 period was 2.91%, while summer peak demand exhibited a 4.06% average annual rate of growth from 1980 to 1990. This forecast incorporates all of the reductions in energy and peak demand that are anticipated to occur due to FPC's latest energy conservation programs. The energy conservation program impacts are a major factor affecting the peak demand forecast and reflect FPC's commitment to conservation, particularly in regards to reducing electrical demands at the time of peak.

For example, FPC's total energy conservation efforts, both historically and during the forecast period, are responsible for a 2,962 MW, or 22.5% reduction in winter peak demand by the year 2009/2010. Just accounting for planned new energy conservation impacts beyond what was available through 1991/1992 yields a substantial 1,959 MW of winter peak demand reduction in the year 2009/2010. This means that 37.7% of any new growth in winter peak demand since 1991/92 is being offset, or reduced, by future new energy conservation program impacts. With regard to summer peak demand, FPC's total energy conservation program impacts provide a 1,526 MW, or 14.0%, demand reduction by the year 2010. On an incremental basis since 1991, new energy conservation impacts are projected to provide a 959 MW reduction by the year 2010. This represents 21.2% of all future growth in summer peak demand between 1991 and 2010.

The high and low sensitivity cases are designed to account for alternative economic and demographic conditions relative to the base forecast. They do not assume abnormal weather conditions and do not assume a different set of energy conservation program impacts from those contained in the base forecast. With respect to energy sales, the high and low cases exhibit average annual growth rates of 4.0% and 2.6%, respectively, between 1991 and 2010. Winter peak demand projections grow at average annual rates of 2.8% for the high case and

Total System Energy Sales

April 1991 Forecast
Figure 2.4

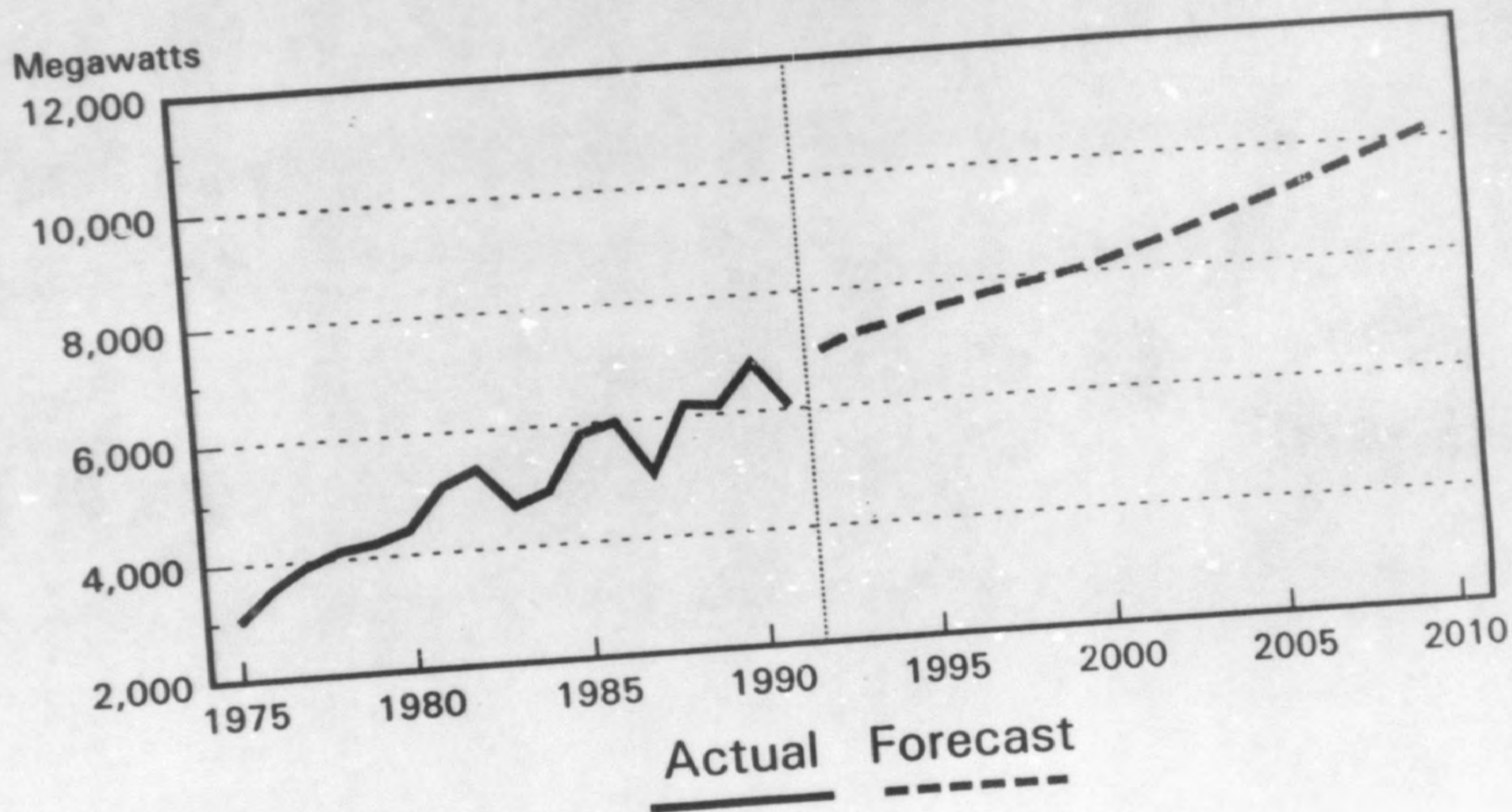


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Winter Peak Demand

April 1991 Forecast

Figure 2.5

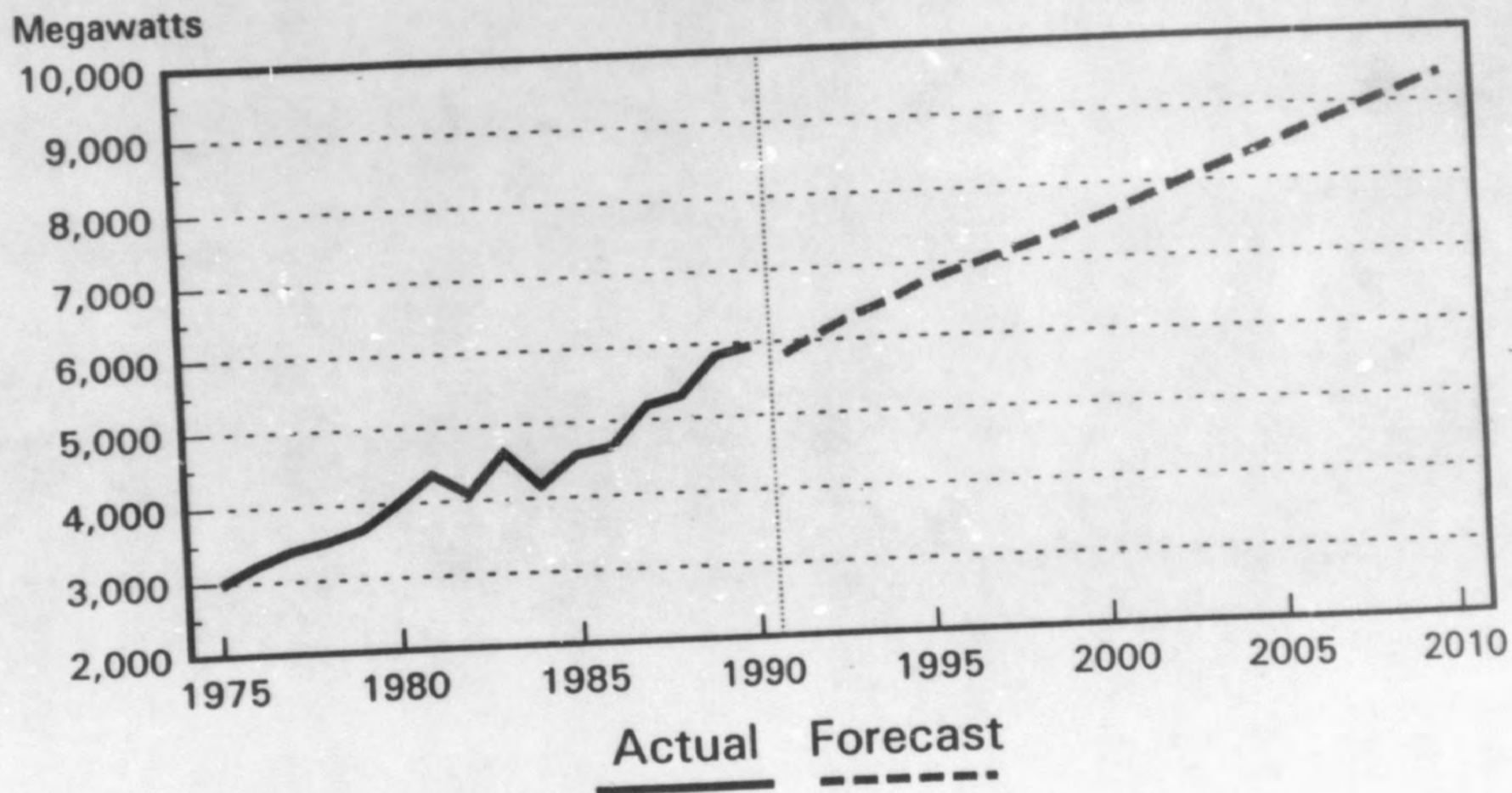


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Summer Peak Demand

April 1991 Forecast

Figure 2.6



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LOAD FORECAST

1.4% for the low case during the 1991/92 to 2009/10 period. High and low summer peak demand cases reveal average annual growth rates of 3.2% and 1.6%, respectively, during the 1991-2010 forecast period.

LOAD FORECAST

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Section 3: EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

INTRODUCTION

This section provides an overview of Florida Power Corporation's past and planned conservation programs. Historical program performance is summarized to illustrate the program's initial contributions to meeting resource needs and the solid customer base that has been established in the residential sector. A description of the expanded 1990s program is provided next, along with estimates of future capacity and energy reductions. Future programs build off of the high degree of customer satisfaction with existing programs and FPC's proven program implementation capability to increase the contributions of nondispatchable energy efficiency programs during the 1990s. The section closes with a discussion of the important role to be played by program measurement and evaluation activities.

CONSERVATION PROGRAMS IN THE 1980s

In 1979 the Florida Energy Efficiency and Conservation Act (FEECA) was enacted. It provided both a mandate and framework for regulated Florida utilities to increase activity in energy conservation. In response to the original FEECA legislation, and in continuation of some of its previous conservation practices, FPC submitted an aggressive Conservation Plan to the Florida Public Service Commission ("the Commission") in January 1981. The Conservation Plan outlined 15 energy efficiency and load management programs.

During the 1980s, Florida Power Corporation made a serious commitment to carry out the FEECA-based conservation programs. Systemwide staffing to support and carry out conservation programs was completed. Resources were allocated to provide field representative training, engineering support, program development, marketing support, program evaluation, and many other associated activities. These measures helped ensure that FPC's conservation programs reached a significant percentage of FPC's customers.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Energy Efficiency Programs In The 1980s

In addition to the residential audits required of all Florida utilities, Florida Power Corporation developed a commercial/industrial audit program, expanded its efficient new home program, and instituted a wide range of other activities that include efficient commercial/industrial building construction, education, streetlight conversion, and voltage regulation. FPC's Home Energy Fixup and Super Saver Home programs were among the first utility undertakings in Florida to ensure that conservation measures actually would be installed.

FPC's energy efficiency programs enjoyed substantial success during the period from 1981 through 1989, as illustrated in the Table 3.1. The Residential and Commercial/Industrial Audit Programs made major penetrations, reaching approximately one-third and one-quarter of their potential markets.

During the decade of the 1980s, Florida Power's energy efficiency programs received national recognition and strong support from customers. For example:

- The Edison Electric Institute presented commendations for FPC's Home Inspection Audits and a large commercial hotel audit. Other awards for conservation programs were granted by the Southeastern Electric Exchange, the International Association of Business Communicators, and the Florida Public Relations Association.
- FPC customers have consistently commended Florida Power for reliable customer service and for helpful energy conservation programs. For example, in the Quarter II survey conducted in May 1991, 79% of the customers queried said Florida Power "does a good job" helping customers save money.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Success of FPC's Energy Efficiency Programs
Table 3.1

Program	Completions	Customer %
Residential Audits	329,117	33.4%
Home Energy Fixup	137,134	14.0%
Efficient New Home	28,259	14.0%
Commercial/Industrial Audits	27,070	23.7%
Commercial/Industrial New Building	6,325	n/a
Education	7,442,312	n/a
Streetlight Conversion	135,426	100%

SOURCE: FEECA Annual Reports and Energy Efficiency Department calculations.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

The strong customer base and in-depth understanding of customer energy requirements gained from the audit programs provides a solid platform for the expanded energy efficiency efforts in the *Partners in Energy* program.

LOAD MANAGEMENT IN THE 1980s

The residential load management program has been the core of Florida Power Corporation's demand-side management programs. There are currently over 600,000 appliances under load management control, and they account for 70% of FPC's demand-side energy resources. Load management has become an integral operating strategy, with a demonstrated capability to provide substantial peak load reduction. For example, load management reduced FPC's winter peak by 650 MW (December 23, 1989).

According to the "1988 Survey of Residential-Sector Demand-Side Management Programs" conducted by the Electric Power Research Institute, Florida Power Corporation had the largest domestic load management program both in absolute terms (most MWs) and relative terms (10% of peak system demand). The program has also received state and national recognition. In 1986, the program was awarded the State of Florida *Governor's Energy Award* for "Innovative Leadership in Energy Conservation." The Edison Electric Institute presented FPC with its *Common Goals Award* for "Outstanding Electric Utility Consumer Program" in 1987.

The load management program enjoys extremely strong acceptance among its 350,000 participants. For example, the 1990 Energy Management Customer Satisfaction Survey revealed a 97.8% satisfaction rating with the program. Three reasons were most often cited for participating in the program: 1) "the monthly credits," 2) "wanted to help Florida Power manage their electric loads more effectively," and 3) "it seemed like the right thing to do." Participants have demonstrated their strong feelings for the program with the majority (83%) of participants signing up for the maximum A/C and space heat control option that has been offered (Schedule B: 16.5 minutes off out of every 30 minutes). In addition, fewer than 2% of all participants have elected to be removed from the program.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Much was learned through the 1980s about the capabilities of direct load control and the willingness of customers to participate in the program. Florida Power became an industry leader in the application of load management technology during the 1980s. For example, Florida Power was instrumental in the development of the first microprocessor-based load control device, which improved both the functioning and the reliability of the product. FPC also developed a control methodology called Distributed Intelligence by which individual appliance diversity (the natural random off/on cycle of air conditioners, etc.) can be maintained during load control. Distributed Intelligence allows larger amounts of controlled loads to be operated smoothly without causing disturbances on the system.

Technical and engineering performance information is being used to formulate alternative control options that will achieve greater per participant load reductions. Innovative marketing approaches are also being formulated to ensure increasing program penetration throughout the 1990s.

NEW PRODUCTS AND SERVICES IN THE 1980s

As part of its commitment to expand cost-effective conservation programs and keep abreast of technology developments, Florida Power Corporation created an expanded organization that could identify, test, and capitalize on the latest, most efficient demand-side technologies. After identifying and thoroughly investigating promising technologies, the New Products and Services program incorporates the most cost-effective and marketable candidates into new program proposals. These proposals are tested and refined in a pilot stage. After successful pilot performance and approval by the Commission, new programs are implemented on a systemwide scale.

A variety of technology and engineering performance investigations were initiated in the late 1980s. These investigations ranged from the application of advanced technologies, such as the 15 KW photovoltaic power generation station ("Solar Progress") to the testing of the impacts of new ASHRAE ventilation standards. In addition, substantial efforts were made to test advanced residential and nonresidential space conditioning equipment.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Several of the technology applications have emerged as offering significant benefits to both Florida Power Corporation and its customers. Brief descriptions of two of these technologies follow.

- **Heat Pipe Technology.** Florida Power Corporation played an instrumental role in testing the application of this heat exchanger technology for humidity control in fastfood restaurants. High humidity levels create substantial discomfort for customers and workers, cause damage from the associated moisture, and represent an expensive cooling requirement. FPC's test demonstrated that the technology could improve indoor relative humidity an average of 15%, which will bring levels well within the comfort range. In addition to increasing comfort, air conditioner electricity consumption was reduced by 17%.
- **HEATWORKS.** HEATWORKS provides residential load shifting capability based on a technology that uses a dedicated thermal storage system. Water is heated during off-peak periods and stored until periods of high demand. During high demand periods, the conventional heating system is interrupted through FPC's regular Energy Management System, and heating energy is available from the storage system.

Florida Power Corporation has developed programs to market these technologies. These programs have met the cost-effectiveness criteria approved by the Commission and provide the basis for effective new energy efficiency programs in the early 1990s. The New Products and Services program continues to test and evaluate potentially attractive technologies.

PROGRAM FUNDING AND SYSTEM IMPACTS IN THE 1980s

Given the influence of national trends, Florida Power Corporation's commitment to energy conservation should be considered in a national context. During the mid- and late-1980s, the national priority given energy conservation decreased dramatically. Fueled in part by the financial drain of the Iran-Iraq war and by new oil production, an OPEC "price war" led to steep reductions in the world price of oil. As oil prices dropped, price stabilization among

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

competing primary energy sources occurred. The United States entered a new era of relatively cheap energy coupled with decreased federal support for energy conservation. The Energy Conservation Commitment graph (Figure 3.1) shows federal support and FPC's support for energy conservation efforts from 1980 to 1990 as figured in 1990 dollars.

To some degree, federal expenditures in energy conservation mirror the general public attitude and level of dedication to conservation. In contrast to the federal government, FPC's financial commitment to conservation grew over the 1980s. By 1990, Florida Power was allocating more than 50 million dollars per year on conservation programs, which equals 25% of the DOE commitment.

Despite implementation during a period of cheap energy and low consumer motivation, FPC's energy programs in the 1980s met many of their capacity and energy reduction goals. Cumulative impacts of FPC's energy efficiency and load management programs are illustrated in Figure 3.2. By 1989, the energy efficiency and load management programs had reduced electrical usage by over 803 GWh and had reduced the winter peak demand by 735 MW.

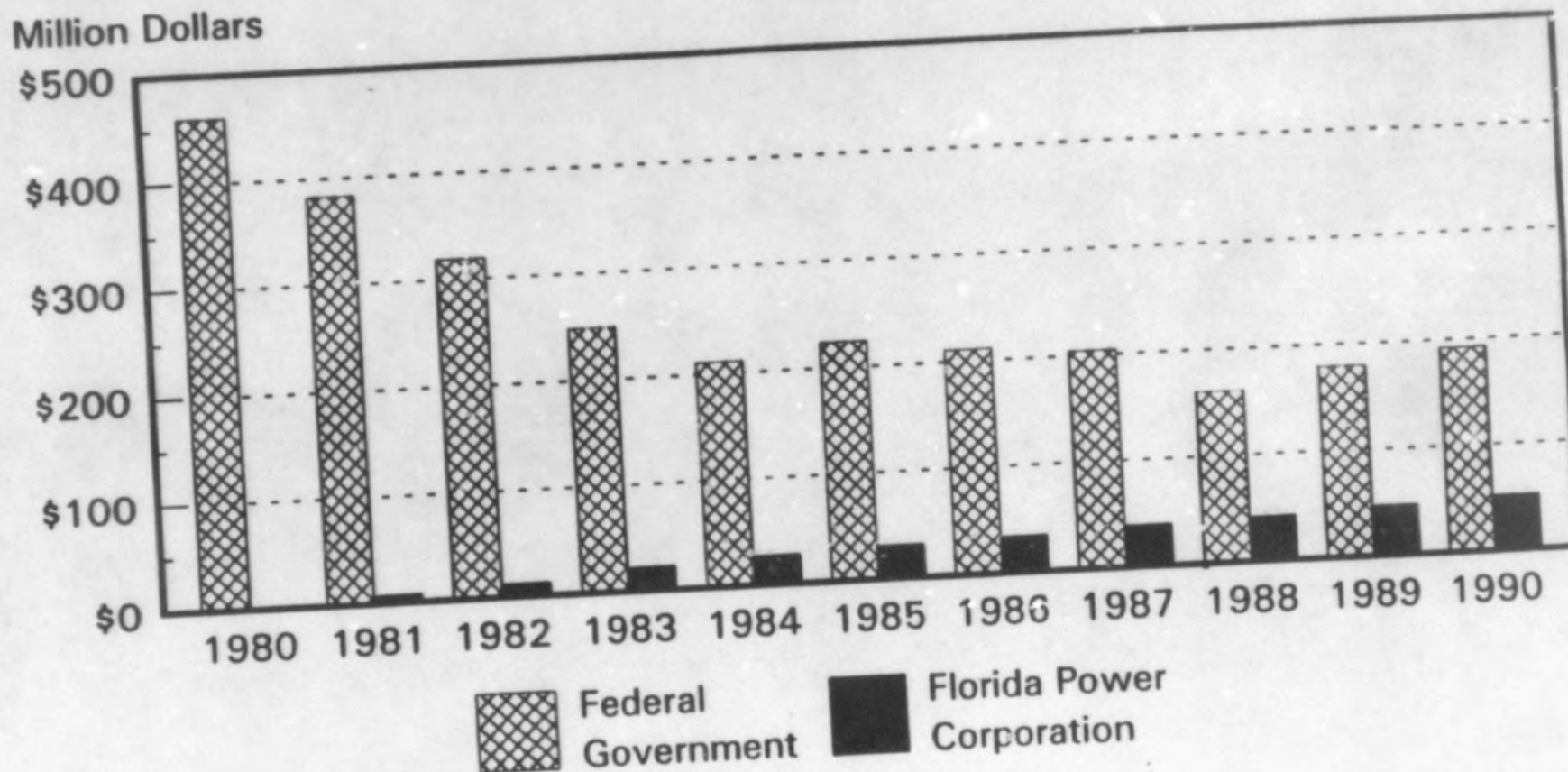
DEMAND-SIDE MANAGEMENT IN THE 1990s

Anticipating the renewal of FEECA legislation, Florida Power Corporation's Energy Efficiency Programs Department began formulating and investigating new and expanded energy conservation efforts. In addition, the Load Management Department submitted an expanded version of the successful load management program.

Energy Conservation Commitment

(In 1990 Dollars)

Figure 3.1



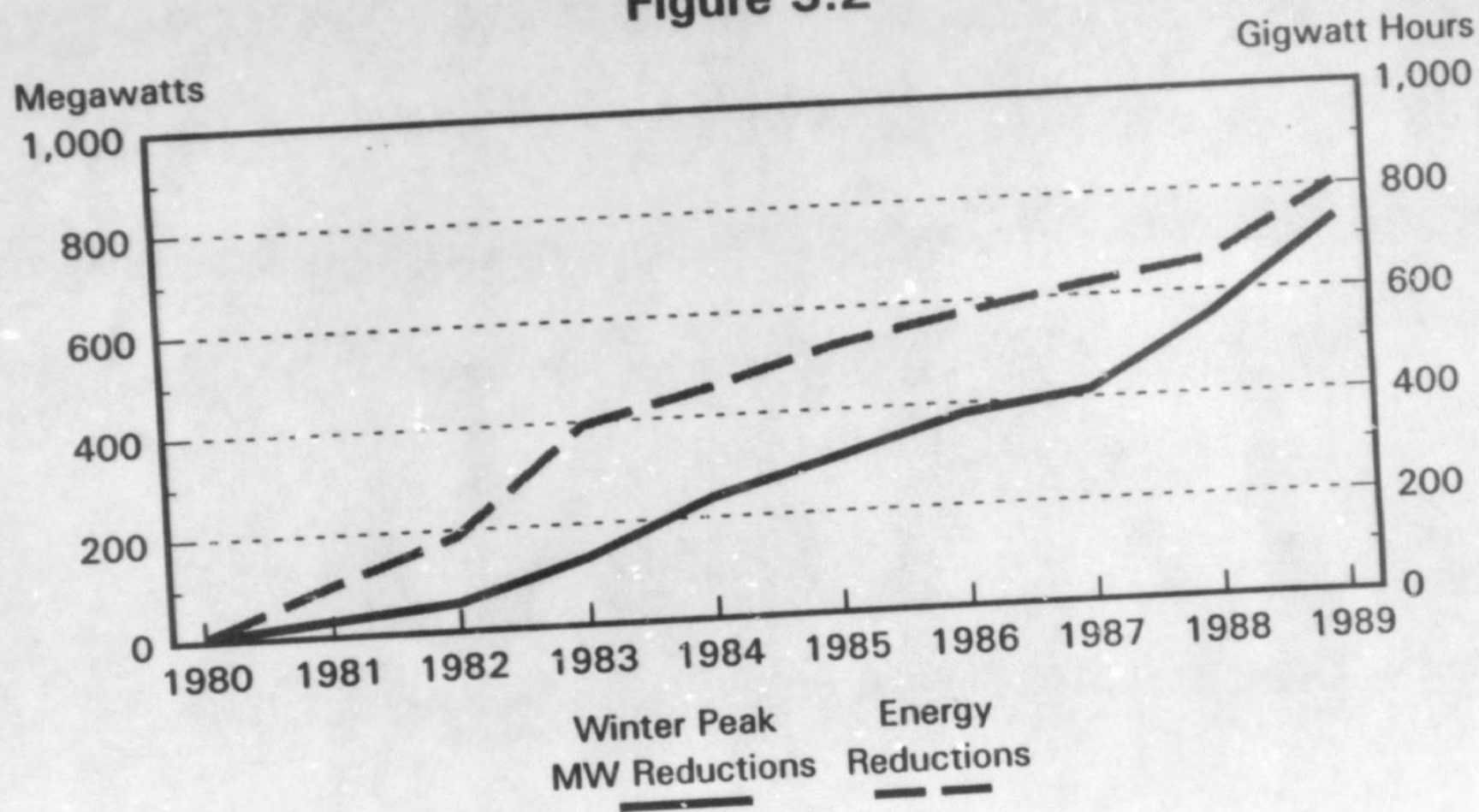
Source: "Energy in Transition," John P. Holdman,
SCIENTIFIC AMERICAN, September 1990.
ECCR True-Up Filings, 1981 - 1991.

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Conservation Program Impacts

Winter Peak and Energy Reductions

Figure 3.2



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EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Florida Power Corporation developed *Partners in Energy*, a new conservation plan with a greatly expanded menu of energy efficiency programs. These programs received the benefit of experience gained from FPC's extensive activities in energy conservation in the late 1970s and throughout the 1980s.

Twenty-two new and/or expanded programs were submitted to the Commission. Brief descriptions of the FPC load management and energy efficiency programs that have been approved by the Commission follow.

Residential Programs

Home Energy Check

During a free Home Energy Check, a certified FPC representative examines the home structure and energy-using equipment. On a written checklist, the representative indicates areas that need conservation actions. The customer is given information on the cost of any recommended repairs or equipment and how much the energy savings would be. In addition, other FPC programs designed to promote energy efficiency are explained. The Home Energy Check addresses the building structure, insulation, caulking and weather stripping, heating and air conditioning systems, and water heating.

Home Energy Analysis

The FPC representative takes specific measurements of the home structure, insulation, and other items affecting energy use. The customer receives a computer analysis covering the cost and energy savings of recommended measures and practices for that residence. The analysis addresses the building structure, insulation, caulking and weather stripping, heating and air conditioning systems, and water heating. There is a \$15 charge for the Home Energy Analysis.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Home Energy Fixup Program

Florida Power Corporation assists the customer in doing minor weatherization energy improvements to the home. If recommended on an audit and agreed to by the customer, FPC arranges for a contractor to do low cost items, including weather stripping, caulking, water heater insulation, and installing low-flow devices in showers. FPC pays half the cost of this work up to \$75.

Load Management

Load Management is a voluntary program that allows Florida Power Corporation to turn off selected energy-using equipment (electric central heating and/or air conditioning, water heaters, and pool pumps) for short intervals during periods of peak electrical usage. Radio-controlled switches allow the equipment to be cycled according to a customer-selected time schedule. The customer receives a credit on the monthly electric bill depending on the equipment and schedule selected.

Comfort Cash Loan Program

If the Home Energy Check determines there are major improvements that can be made to conserve energy, a low interest loan may be available. The program can fund items such as heat pumps or other high efficiency central air conditioning systems and heat recovery or heat pump water heating equipment. Interest rates are subsidized with the maximum loan amount set at \$5,000.

Air Conditioning Duct Test and Repair

If recommended during a Home Energy Check, a pressure test can be done on the home's central duct system. This identifies any air leaks that could cause energy loss by infiltration or exfiltration. The customer then has the option to have those leaks repaired. FPC pays half the cost of the test and the repair up to \$125. Repairing these energy leaks will save significantly in home heating and cooling costs.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Insulation Upgrade

Florida Power Corporation will assist the customer in upgrading ceiling/attic insulation to reduce energy losses for heating and air conditioning the home. If a Home Energy Check shows that insulation in the home is less than R-12 (an index of insulation value), FPC will pay up to \$75 to have the insulation level improved to a minimum of R-19. The customer obtains competitive bids from FPC-approved contractors.

Air Conditioning Service

If the Home Energy Check indicates the need for air conditioning or heat pump service, Florida Power Corporation will give the customer a \$5 certificate toward this service. The customer can select an FPC-approved contractor.

HEATWORKS Heating Storage System

Water is heated in a dedicated storage thermal tank during off-peak hours. During periods of high demand, the domestic heating system is interrupted, and heating from HEATWORKS is available in place of the customer's regular heating system. Equipment in the home is controlled through FPC's regular Energy Management System.

High Efficiency Air Conditioning Promotion

Florida Power Corporation offers an incentive program for dealers to sell high efficiency central air conditioning systems, heat pumps, and heat recovery or heat pump water heating equipment. The incentive program awards points to the dealers that can be redeemed for merchandise gifts. FPC specifies the minimum efficiency ratings to qualify for the program.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Trade Efficiency

FPC representatives keep in close contact with the residential and commercial building trades. Seminars are sponsored on the Florida Energy Efficiency Building Code, on how to build an energy efficient home, and on energy-saving equipment. The ductwork in model homes on display can be pressure tested for air leakage and repaired. Builders are required to incorporate any changes indicated by the pressure test in the balance of homes built within that development.

Commercial/Industrial/Agricultural Programs

Business Energy Check

The Business Energy Check is an inspection of a commercial/industrial facility's lighting, building envelope, water heating system, heating, ventilating, air conditioning, and other energy-using systems. A written checklist is given to the customer indicating areas that need conservation action. The representative explains other FPC programs that would incorporate energy-efficient actions or equipment. There is no charge for the Energy Check.

Business Energy Analysis

The Analysis is an in-depth study of a commercial/industrial customer's facility. The computer-assisted analysis identifies the sources of energy consumption and makes written recommendations on how to improve energy efficiency. A certified Florida Power representative or engineer completes a thorough energy study. Specific recommendations are made for conservation actions with information on cost, energy savings, and payback time for each alternate recommendation. The cost of the analysis is based on the average monthly energy use of the facility. If recommendations are implemented, the implementation cost is refunded to the customer up to the audit cost less \$35.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Air Conditioning Duct Test and Repair

If recommended during an Energy Check or Analysis, a pressure test can be performed on the central duct system. This identifies any air leaks that could cause energy loss by infiltration or exfiltration. The customer then has the option to have those leaks repaired. Florida Power will pay up to \$125 of the cost of the test and repair procedure. Repairing these energy leaks will save significantly in heating and cooling costs.

Interior Lighting Conversion

Florida Power Corporation provides rebates to business customers who install preapproved lighting products designed to reduce energy consumption and demand. Lighting system changes approved for rebates include high efficiency fluorescent and incandescent lamps, electronic ballasts, and compact fluorescent lamps. The customer selects a contractor to perform the work.

Air Conditioning Service

If the need for air conditioning service is identified during an Energy Check, Florida Power Corporation will give the customer a \$5 certificate toward this service. Central air conditioners and heat pumps of 60,000 BTU or less are eligible. The customer can select an FPC-approved contractor.

Business Energy Fixup

The Business Energy Fixup provides minor weatherization repairs as identified in an Energy Check. Authorized measures include caulking, weather stripping, door sweeps and thresholds, window film, water heater insulation, faucet aerators, lamp replacement, and HVAC filter replacement. FPC will pay half the cost of these services (up to \$100) if handled by an approved contractor.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

Commercial/Industrial HVAC Promotion

Florida Power Corporation conducts an incentive program for air conditioning dealers to sell high efficiency central air conditioning, heat pumps, and heat recovery or heat pump water heating equipment. Eligible equipment is limited to 60,000 BTU or less. The incentive program will award points to the dealers that can be redeemed for merchandise gifts. Efficiency ratings to qualify for this program are specified by FPC.

Motor Replacement Rebate

This program offers an incentive to customers to replace inefficient motors with high efficiency types. To be eligible, the customer must have an FPC Energy Check or Analysis. Florida Power Corporation will specify efficiency ratings of the old and new equipment that will qualify for the rebate.

Heat Pipe Development

Florida Power Corporation encourages the installation of heat pipe equipment to control humidity and reduce energy use. Buildings that require humidity control must supercool air and then reheat it in order to remove moisture and bring the air to acceptable humidity levels. Heat pipes accomplish the reheating process without consuming energy. Eligible customers and rebate amounts are determined during the project's design phase and are dependent on the customer's system configurations.

Demand Reduction Capital Offset (DRCO)

The DRCO program has been designed to encourage significant conservation efforts that are not addressed by other FPC incentive programs available to commercial, industrial and agricultural customers. DRCO provides Florida Power Corporation with the flexibility to offer economic incentives for increasing the penetration of demand and energy reduction measures tailored to the specific needs of these larger customers. Under this program, FPC will be able to work with individual customers to pursue all cost-effective conservation

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options. For example, after passing an engineering evaluation, major equipment replacements or other conservation actions will qualify for the economic incentive.

New Program Development

A procedure was approved allowing Florida Power Corporation to recover development, research, and design costs for programs that could become cost-effective conservation programs. This ensures that, as new technologies are investigated and refined, a mechanism exists to allow FPC to incorporate them in its demand-side management planning.

DEVELOPMENT OF THE MAXIMUM AVOIDABLE CAPACITY SCENARIO

Driven by its commitment to integrated resource planning, Florida Power prepared its Maximum Avoidable Capacity Scenario (M.A.C.S.) for energy efficiency and load management. M.A.C.S. has been structured to attain the highest KW demand and associated energy reductions from programs that meet the Commission's cost-effectiveness tests.

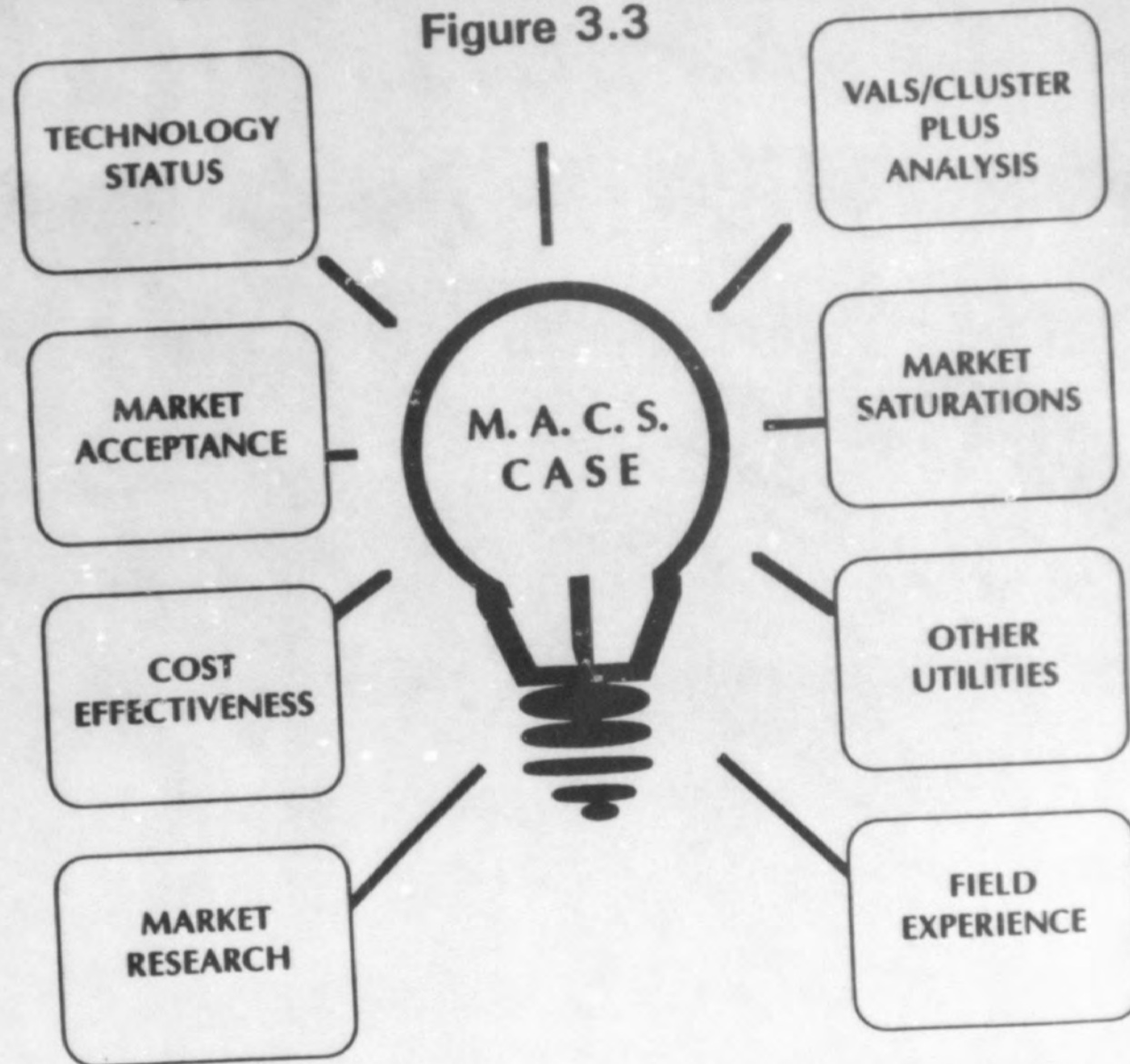
Development

The development of M.A.C.S. required the consideration of many new types of technology and extensive market data and reliance on the management and implementation experience that Florida Power has gained over the past decade. The input sources for M.A.C.S. are illustrated in Figure 3.3 and described briefly below:

- **Technology Status.** Research and evaluation of available technologies to provide the most advanced programs possible. Recognition that technologies available are greatly advanced over the previous decade.
- **Market Acceptance.** Evaluation of customer concern about energy conservation, the environment, the economy, and other issues which affect customer interest in DSM programs and ultimate penetration levels.

INPUTS FOR M.A.C.S.

Figure 3.3



EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

- **Cost Effectiveness.** Evaluation of programs to ensure that programs meet the Commission's requirements.
- **Market Research.** Research to determine customer satisfaction with FPC programs and services, to measure program impacts, and to provide input for new program development.
- **VALS and ClusterPLUS Analysis.** Geodemographic, psychographic, and economic analysis of customer segments to develop targeted marketing strategies.
- **Market Saturations.** Estimates of program potential based on current saturation levels, population growth forecasts, and response rates to marketing efforts.
- **Other Utilities' Experiences.** Evaluation of the experiences of other utilities in implementing and marketing similar programs.
- **Field Experience and Input.** Ten years experience with techniques and results, including understanding customer needs and implementing programs.

Under M.A.C.S., over 1,000 MW of incremental dispatchable DSM capacity is planned for the 1990s. By 2001, this will amount to approximately 1,659 MW of winter peak demand reduction. Energy efficiency programs will reduce winter peak demand by 723 MW by 2001. These efficiency improvements will reduce annual consumption by 778 GWh in the same year. Total M.A.C.S. impacts are listed in the corporate forecast in Appendix A.

M.A.C.S. has been adopted by Florida Power and incorporated as the standard adjustment to FPC's corporate load forecast. This adjustment occurs before and in conjunction with energy resource alternative analysis.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

MARKETING AND MEASUREMENT ASPECTS OF M.A.C.S.

Marketing

The marketing of the energy efficiency programs in the 1990s will focus on increasing both the breadth and the depth of program saturation: breadth by reaching customers who have never before participated, and depth by reaching customers who may have previously participated in some programs, but have the potential to benefit from new and enhanced programs. For example, customers who have participated in earlier audit programs represent a potentially untapped market that can now be addressed with the available financial incentive programs.

M.A.C.S. builds from Florida Power's strengths in the residential sector to significantly expand the capacity and energy reductions obtained by load management and nondispatchable energy efficiency programs. In the residential sector, M.A.C.S. load management goals will be achieved through increasing customer participation on existing load control schedules and through the development and marketing of new load control schedules, which have the potential to significantly increase the reductions obtained from each individual customers.

New load control schedules provide the opportunity to achieve M.A.C.S. load management goals with significantly lower penetration rates than would be required under existing load control schedules. For example, Florida Power Corporation has tested a schedule that calls for up to a six-hour interruption of central heating or cooling equipment during the control period. A 1991 winter pilot of the new schedule revealed that winter peak load reductions of 4 kilowatts per customer are attainable. This reduction is approximately twice the demand reduction of Schedule B central heating. A summer pilot program is currently underway.

Through the latter half of the 1980s, over 44,000 customers per year were being added to FPC's load management program (see Table 3.2). To achieve the load reduction targets for M.A.C.S., 62,500 customers per year would need to be added under existing load control schedules. Alternatively, the diversified MW equivalent reductions could be obtained with

Residential Load Management
Table 3.2

Year	Residential Load Management Installations
1981	48
1982	14,250
1983	36,752
1984	25,395
1985	32,232
1986	42,300
1987	43,151
1988	40,508
1989	42,498
1990	52,442
Total For 1986 - 1990 :	
Average For 1986 - 1990 :	
	220,899
	44,180

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historical participation rates if approximately half of the customers were to choose a control schedule such as the one discussed above.

Increased program emphasis is also being placed on obtaining cost-effective DSM resources from the commercial, industrial, and agricultural sectors. Targeted, end-use specific incentive programs (e.g., Heat Pipes, Interior Lighting Conversion, and Motor Replacement Rebate) will be employed along with the flexible Demand Reduction Capital Offset program, which allows Florida Power Corporation to provide larger customers with incentives for any and all cost-effective conservation measures that meet specified engineering evaluation criteria. The combination of incentive programs will allow FPC to tap available capacity and energy reduction opportunities in these nonresidential sectors.

A marketing analysis of the load management program clearly indicates excellent growth potential for the program. Merely bringing the high growth divisions up to the saturation levels already achieved by other divisions will add a minimum of 100,000 customers. Response to the program in its current form continues to be excellent in the originating Divisions, an indication that the markets are far from saturated. The current low saturations and high forecasted growth in the Eastern and Mid-Florida Divisions indicates that the M.A.C.S. projected goals are reachable. The development of new schedules and programs with increased appeal, coupled with more sophisticated marketing techniques, will enable Florida Power Corporation to achieve M.A.C.S.

Measurement

Reliable measurement and projection techniques are essential for establishing conservation program cost effectiveness. Florida Power Corporation, and the utility industry in general, have developed techniques to provide a high degree of confidence in the estimation of impacts and cost effectiveness of load management programs. However, the reliability of measurement and projection techniques for energy efficiency programs is not as well developed, and is an area of concern throughout the utility industry.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

As part of its increased emphasis on energy efficiency programs, Florida Power Corporation has placed a priority on increasing the level of reliability of energy efficiency program measurement. To meet this challenge, FPC is constituting a new group whose prime responsibility will be measurement and evaluation of demand-side management programs.

The group will be undertaking efforts to develop advanced models that provide the basis for statistically isolating the impacts induced by FPC's programs from those caused by physical (e.g., weather) influences and changes in general economic and business conditions. This allows more accurate estimates of the cost effectiveness of energy efficiency programs. Statistical models must be coupled with an adequate sample base; therefore, large scale data collection will be an important function of the new measurement group. Finally, market research on customer responses and engineering research on long-term effectiveness of efficiency measures will be factored into the statistical models to provide the basis for projecting future program impacts.

Feedback from measurement activities allows Florida Power Corporation to begin to more accurately gauge the effectiveness of energy efficiency programs for the 1990s.

In addition, this information provides the basis to modify and refine programs to ensure they meet customer needs and achieve their demand and energy reduction objectives.

CONCLUSION

M.A.C.S. is an evolutionary DSM program that demonstrates the pivotal role that conservation resources play in FPC's planning and future resource acquisition efforts. M.A.C.S. reflects the maturation of FPC's cost-effective load management efforts, which were initiated during the 1980s, and the expansion of energy efficiency programs as recently approved by the Commission. The 1990s programs build from FPC's strengths in the residential sector to significantly expand the capacity and energy reductions obtained by nondispatchable energy efficiency programs in the residential sector. Increased program

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

emphasis is also being placed on obtaining cost effective DSM resources from the commercial, industrial and agricultural sectors.

Residential load management efforts remain the cornerstone of FPC's efforts to limit future peak load growth during the 1990s. Load control schedules and payment combinations are being refined to enhance the program's appeal to the full range of residential customers and ensure that associated capacity reduction targets are achieved.

Expanded energy efficiency programs are targeted for both residential and nonresidential customers. Residential programs focus on reducing space conditioning electricity use. Commercial, industrial, and agricultural programs also focus on space conditioning, but also include programs to reduce lighting loads and provide incentives for all cost-effective reductions in capacity and electricity use.

EXISTING AND PLANNED DEMAND-SIDE MANAGEMENT

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Section 4:

FUEL PRICE FORECAST

INTRODUCTION

This section presents FPC's fuel price forecast, which was developed as one of the basic inputs to the alternative capacity planning process. The projected difference in cost between the various types and grades of fuel is one of the economic factors that determines the type of generation required, the most economic way to operate each plant, and the optimum way to comply with Clean Air Act requirements.

FORECAST METHODOLOGY

Florida Power Corporation developed a Base Case Price Forecast for each type of fuel expected to be available and potentially used at existing or future generating plants. The Base Case is considered the most likely set of prices with a 55% probability of occurrence. The projected prices are provided on an annual basis in nominal dollars and usually project a trend over several years where specific prices are given. After the first several years (5 to 10, depending on the fuel), the forecast price changes are projected to equal the general rate of inflation. This is done for two reasons. First, after several years of projected prices, it is expected that the relationship between the prices of different fuels will have stabilized. Adjusting prices only for changes in general inflation after that point maintains the relationship between prices of the various fuels in real terms. Secondly, the further out in time prices are projected, the more uncertain the forecast becomes. The relationship between the prices of the various fuels is more important to determining planning options than the absolute level of the prices. This method establishes these relationships without distorting the distant future with real price changes that are subject to significant uncertainty.

In addition to the Base Case, a Low and High Case forecast were developed. The Low Case was considered slightly more likely than the High Case. Therefore the Low Case was assigned a probability of 25%, and the High Case was assigned a probability of 20%. Each of these cases is based on potential circumstances that could result in higher or lower prices

FUEL PRICE FORECAST

than the Base Case, and each is linked over the long range to a higher or lower rate of general inflation than the Base Case. In other words, low fuel prices are likely to occur in and/or contribute to a low inflation environment. Therefore, after the first several years of specific price changes, the Low Case fuel prices are assumed to change at the same rate as the Low Case general inflation rate. Alternatively, high fuel prices occur in and/or contribute to a higher than base inflation rate. Therefore, after the first several years of specific price changes, the High Case fuel prices are assumed to change at the same rate as the High Case general inflation rate.

Price forecasts are developed for coal, oil, natural gas, nuclear fuel, and orimulsion. In the case of coal and oil, prices for several different grades or types of each are projected based on significant price differences between them. The forecasted fuel prices for the base, low, and high scenarios are shown in Figures 4.1, 4.2, and 4.3. Tables with more details about the forecasted prices are shown in Appendix B.

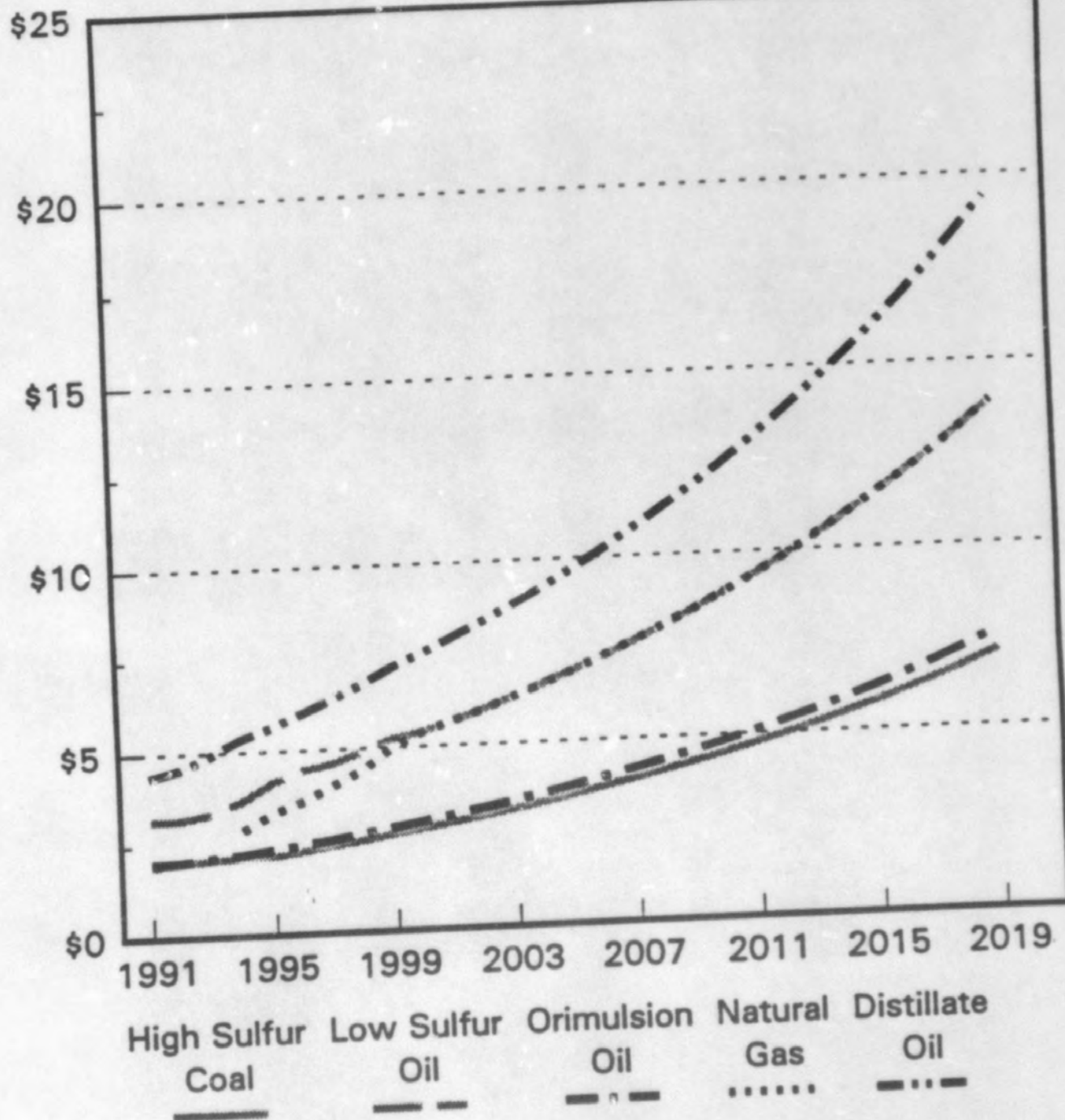
COAL PRICE FORECAST

Coal prices were forecasted for the two types of coal currently in use at Crystal River Plant. Coal for Crystal River 1 and 2 is limited to 2.1 lbs. SO_2 per million BTU, while coal for Crystal River 4 and 5 is limited to 1.2 lbs. SO_2 per million BTU. Near-term prices are impacted by current contracts in place, the transportation system for delivering coal to Crystal River, and the coal market (as it impacts market re-openers and spot market purchases). In addition, a forecast was developed for a medium to high sulfur coal to be delivered to a potential new unit in Central Florida. This type of coal was assumed to be the most economical type to be supplied to a new scrubber-equipped conventional coal plant or a coal gasification plant. Transportation to the inland site was assumed to be a combination of direct rail from Central Appalachia and combination barge and rail deliveries utilizing the Mississippi River and the Gulf Barge System and delivering to a West Coast Florida Port with transshipment by rail to the plant site. The major factors that cause the price difference noted for the High and Low Cases are those basic factors that affect both supply and demand. In all cases, the supply of coal is expected to be abundant.

Forecasted Fuel Prices : Base Scenario

Figure 4.1

Nominal \$/ MmBtu



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Forecasted Fuel Prices : Low Scenario

Figure 4.2

Nominal \$/ MmBtu

\$14

\$12

\$10

\$8

\$6

\$4

\$2

\$0

1991 1995 1999 2003 2007 2011 2015 2019

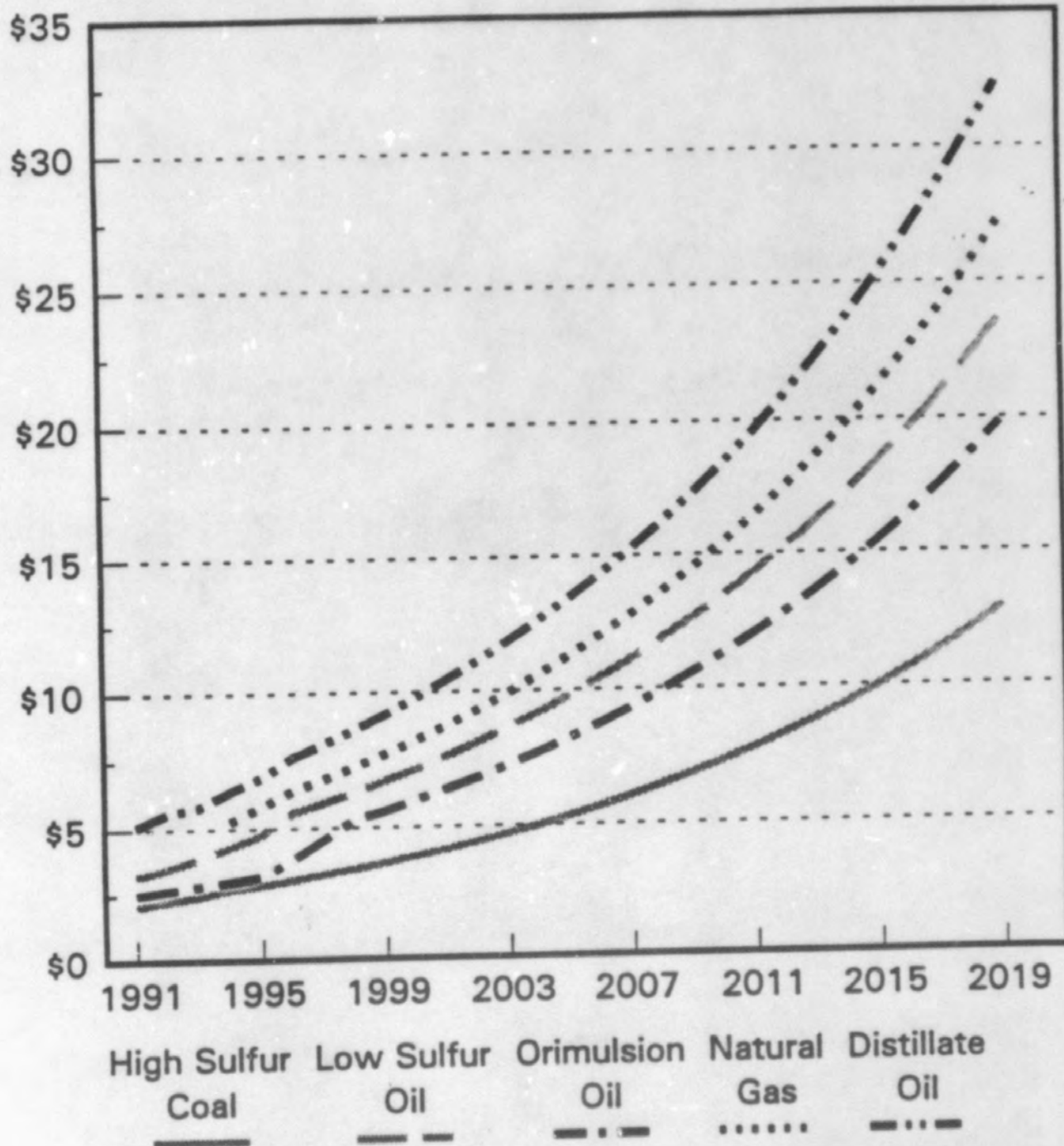
High Sulfur Coal Low Sulfur Oil Orimulsion Oil Natural Gas Distillate Oil

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Forecasted Fuel Prices : High Scenario

Figure 4.3

Nominal \$ / MmBtu



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FUEL PRICE FORECAST

The Low Case assumes that demand for coal is lower than in the Base Case. The advances in productivity of the last several years continue at a rapid pace, keeping mining cost increases below the rate of inflation for the first several years, after which prices are assumed to increase at the Low general inflation rate.

In the High Case, demand for coal is expected to be higher than in the Base Case as the even higher prices for alternative fuels makes coal a more attractive fuel source. The demand for lower sulfur coal (such as that used at the Crystal River Plant) is in higher demand due to the impact of the Clean Air Act. The higher demand, fewer productivity improvements in mining, and the higher inflation environment combine to drive coal prices higher than in the Base Case and higher than the rate of inflation for the first few years. After that, prices are assumed to increase at the High rate of inflation.

OIL PRICE FORECAST

Oil prices were forecasted for three sulfur grades of residual fuel oil and for No. 2 fuel oil. One percent and 2.5% sulfur residual fuel oil are used at several existing steam plants. If required for clean air compliance, .3% sulfur residual fuel oil could be available as a lower sulfur oil for these same plants. Alternative grades in between these are potentially available through blending and costs can be estimated by interpolation. Significant quantities of residual oil below .3% sulfur are not expected to be available. No. 2 fuel oil is utilized by combustion turbines and at steam plants for start-up and flame stabilization. It potentially can be used as a backup fuel for natural-gas-fired plants.

Price forecasts for oil are given as waterborne bulk deliveries to the West Coast of Florida. Transportation adders to deliver the oil to individual plants are provided separately.

The key factors in the oil forecast are the assumed strategy of OPEC, the overall world supply and demand balance, and the relative demand for lower sulfur fuels. In the Low Case, supply is abundant and OPEC control is relatively weak. In the High Case, OPEC control is stronger, restricting supply, and non-OPEC production is limited. In the High Case, the demand for very low sulfur oil is greater than in the base case (due to the Clean

FUEL PRICE FORECAST

Air Act and similar environmental measures in other countries) and therefore the premium for low sulfur oil is higher, particularly for .3% residual oil and No. 2 fuel oil.

NATURAL GAS PRICE FORECAST

Natural gas prices were forecasted for a new pipeline source for delivery to a Central Florida location. The forecast is formatted into a variable and fixed component. The variable component includes the cost of the natural gas delivered in the producing area at general market prices plus the variable component of the pipeline transportation charge. The fixed component is the estimated demand charge for firm pipeline transportation capability. The pipeline transportation component was estimated from recent pipeline rate case filings and other independent sources. No producer demand charges are assumed for the natural gas supply itself.

In the Base Case, natural gas is competitively priced with 1% sulfur residual fuel oil. In the Low Case, natural gas is assumed to be in relative surplus and therefore would be priced somewhere between 1% and 2.5% sulfur residual oil on a delivered basis into Florida.

In the High Case, natural gas is expected to reflect a premium price due to its clean burning characteristics and the increasing demand for it as a power plant fuel. Not only will it be

FUEL PRICE FORECAST

needed for new combustion turbine-based generation, but to reduce sulfur emissions at existing steam plants to comply with sulfur emission caps dictated in the Clean Air Act. In this case, natural gas will be priced competitively with .3% sulfur residual oil.

The relatively higher or lower pipeline demand charges in each case are due to lower or higher inflation forecasts and their impact on the capital cost of the pipeline.

ORIMULSION PRICE FORECAST

Orimulsion is a mixture of very heavy oil and water being produced in Venezuela. This product is being made available as a power plant fuel in competition with coal. The price forecast assumes that this fuel is delivered to the West Coast of Florida in bulk quantities and transshipped to a Central Florida location.

In the Base Case, this fuel is generally priced in competition with the average cost of coal delivered into Florida. This price parity with coal has been the stated objective of the producer and reflects its primary competition. Like coal, this fuel requires extensive pollution control equipment to allow it to be burned. In the Low Case, the price is competitive with Medium to High Sulfur Coal. In the High Case, the fuel is initially priced competitively with coal but climbs to residual oil related prices in later years. This assumes that since orimulsion is a liquid fuel it will eventually command a liquid fuel price in a High Case environment.

NUCLEAR FUEL PRICE FORECAST

Nuclear fuel amortization projections (nuclear fuel expense) are based on a combination of actual dollar expenditures, estimates of future cash expenditures for contractual commitments, projected allowance for funds used during construction (AFUDC) of each reload batch, and the amount of energy (BTUs) extracted during a particular cycle from each batch utilized.

FUEL PRICE FORECAST

In the Base Case, long-range cost escalates with the Base General Inflation Rate. The Low Case escalates with the Low General Inflation Rate and the High Case escalates with the High General Inflation Rate.

FUEL PRICE FORECAST

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Section 5:

EXISTING AND PLANNED GENERATION

INTRODUCTION AND OVERVIEW

A determination of the need for additional generation is necessarily based on a careful assessment of FPC's existing and planned resource additions. This section describes the generation and transmission resources available to the FPC system. The existing system, including generating plants, substations, and transmission lines, is shown in Figure 5.1. Together with DSM and Qualifying Facility resources, the resources described in this section form the baseline for evaluating alternative generation expansion plans.

Florida Power Corporation's current generating facilities consist of 53 generating units with an aggregate winter generating capability of 6,621 MW as of January 1992. These generating units are located at 12 generating sites across the state of Florida. Table 5.1 lists all FPC generating units along with their winter net capacity rating.

Florida Power's generating units provide an excellent mix of generating capabilities that range from base load units (continuous operation) to peaking units. Generally speaking, FPC classifies generation resources as base load if they have a 70% or higher capacity factor, i.e., they provide the system at least 70% of their maximum possible generation. Similarly, generation resources are classified as "intermediate" or cycling capacity if their capacity factor falls between approximately 30% and 70%. Generators designed to operate at capacity factors less than 30% are classified as peaking plants.

A properly functioning and cost-effective electric power system contains a mixture of base, intermediate, and peaking generators. FPC's existing generation mix has allowed FPC to meet the various demands of its customers in a cost-effective manner.

Florida Power's five base load units are located at Crystal River, FPC's largest generating site. Florida Power's share of the Crystal River nuclear plant (Crystal River 3) produces 760 MW of base load generation. The four Crystal River coal plants (Crystal River 1, 2, 4,

EXISTING AND PLANNED GENERATION

Figure 5.1

(Please see Key Map at the back of this Study.)

Serc Net Maximum Generating Capacity for Winter 1992
Table 5.1

STEAM PLANTS	WINTER	COMBUSTION TURBINES	WINTER
	(Net MW)		(Net MW)
ANCLOTE 1	517	AVON PARK P1-P2	60
ANCLOTE 2	502	BARTOW P1-P4	212
BARTOW 1	108	BAYBORO P1-P4	216
BARTOW 2	119	DEBARY P1-P6	330
BARTOW 3	215	HIGGINS P1-P2	60
CRYSTAL RIVER 1	373	HIGGINS P3-P4	66
CRYSTAL RIVER 2	469	INTER. CITY P1-P6	342
CRYSTAL RIVER 3 *	760	SUWANNEE P1-P3	195
CRYSTAL RIVER 4	717	TURNER P1-P2	34
CRYSTAL RIVER 5	717	TURNER P3-P4	160
HIGGINS 1	40	RIO PINAR P1	17
HIGGINS 2	42	PORT ST. JOE P1	17
HIGGINS 3	41		
SUWANNEE 1	34	TOTAL PEAKING	1,709
SUWANNEE 2	33		
SUWANNEE 3	80		
TURNER 3	72		
TURNER 4	73		
TOTAL STEAM	4,912		
TOTAL SYSTEM	6,621		

* Represents 90 % FPC ownership of unit

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and 5) produce 2,276 MW of base load generation. The Crystal River site represents 3,036 MW or 46% of FPC's capabilities. This base load generation provides continuous low cost energy for Florida Power customers' aggregate constant energy demands.

Oil-fired steam units provide backup base load generation. These units function as intermediate or cycling generation. Intermediate generation is typically needed to accommodate loads that are lower and of longer duration than system peak periods but higher than base periods. This is seen in the summer and winter months along with other days in which customers demands are above base loaded capabilities. Oil-fired steam units are started and shut down (cycled) to match customers' aggregate daily energy demands. These plants include Anclote 1 and 2; Bartow 1, 2, and 3; Turner 3 and 4; Suwannee 1, 2, and 3; and Higgins 1, 2, and 3. These plants represent 1,876 MW of intermediate generation, or 28% of FPC's capabilities.

The remaining FPC generation consists of peaking generators that are designed to meet the customers short-term peak energy demands. On the FPC system, peaks typically occur during the summer afternoons and winter morning and evening hours. FPC's total peaking capacity is 1,709 MW, or 26% of FPC's capability. The peaking units are located at DeBary P1-P6, Intercession City P1-P6, Suwannee River P1-P3, Bartow P1-P4, Turner P1-P4, Bayboro P1-P4, Higgins P1-P4, Avon Park P1-P2, Rio Pinar, and Port St. Joe.

RECENT SYSTEM ACTIVITIES

Florida Power Corporation's most recent generation construction was completed with the addition of Crystal River 4 and 5 in 1982 and 1984, respectively. These two large coal units have a capacity of 717 MW each. Their excellent heat rates have allowed Florida Power to rank in the top 10 among the 100 largest investor-owned utilities for fossil steam unit efficiency.

In 1984 the Avon Park 2 steam unit was placed on extended cold shutdown. Turner 2 steam unit was placed in maintenance shutdown in 1987. The in-service dates of these plants are 1948 and 1952, respectively. FPC has proposed to lease the Avon Park 2 unit to the EcoPeat

EXISTING AND PLANNED GENERATION

Corporation for the purposes of constructing a QF project that will burn a low cost Florida peat fuel. FPC's economic studies include the EcoPeat unit as one of FPC's many small power producer supply resources (see Section 6). In May 1991, FPC has determined to retire Turner 2.

Since 1988, Florida Power has returned to service approximately 626 MW of peaking capacity. These units had been operational up until the mid-1980s, at which time they were placed on extended cold shutdown. These peaking units have helped Florida Power to delay new construction until November of 1992. The peaking capacity returned to service consists of 212 MW at the Bartow site, 194 MW at the Turner site, 126 MW at Higgins, 60 MW at Avon Park, 17 MW at Rio Pinar, and 17 MW at Port St. Joe.

PLANNED GENERATION

In November of 1992, Florida Power plans to place in service an additional 364 MW of peaking capacity at the DeBary site. Presently, there are six peaking units at DeBary totaling 330 MW. The new addition to DeBary consists of four General Electric model 7EA combustion turbines rated at 91 MW each. This addition will increase the output of the DeBary plant to 694 MW. By November of 1993, another addition of 364 MW of peaking units is planned for the Intercession City site. Presently, there are six peaking units at Intercession City with a site rating of 342 MW. The addition will increase its capacity to 706 MW.

In November of 1993, FPC is planning to install a 40 MW heat recovery generating unit that will be located at the University of Florida. This unit will be fueled by natural gas and will provide steam to the university as needed. The unit will consist of a GE LM6000 gas turbine with an excellent heat rate. The unit's excellent heat rate, along with natural gas fuel supply and with steam sales to the university, will allow this unit to serve as a base load or intermediate load unit.

After the addition of the DeBary, Intercession City, and University Project units, the winter generation capacity of the FPC system as of January 1994 will be 7,389 MW.

EXISTING AND PLANNED GENERATION

PLANT RETIREMENTS

FPC's filing in the investigation of the rate-making and accounting treatment for the dismantlement of fossil-fueled generating stations shows the Higgins Steam, Higgins Peaking, and Avon Park Peaking units scheduled for retirement in the years 1998, 2001, and 2000, respectively. In this Study, the retirements of the Higgins Steam and Peaking units were combined to form a new plant retirement date of 1999. The 1999 date will allow treatment of the Higgins Steam and Peaking units as a common dismantlement project with a minimum steam retirement age of 45 years for steam units and 29 years for peaking units. The retirement of the Avon Park peakers was not changed and are planned for the year 2000. The retirement of these plants will allow FPC to begin removing the older oil-fired technology units and plan for new generation with clean and efficient technologies that will meet future environmental and emission regulations.

PROPOSED GENERATION

The four 235 MW combined cycle units scheduled for the year 1998 through 2000 operate as intermediate (55% capacity factor) units on the FPC system. These units have the ability to run base load (continuous duty) as required. The combined cycle units will operate on natural gas. The units' excellent heat rate along with the predicted price of fuel cause these units to be dispatched after the base loaded Crystal River units and before the oil-fired steam units. This dispatch order requires the combined cycle units to operate in a base or an intermediate mode (cyclic duty). The cyclic duty operation is part of the design requirements of the combined cycle units and will allow efficient and fast response to system changes. The units' natural gas fuel supply with zero sulfur emissions plays a critical role in FPC's achievement of its compliance requirements under Phase II of the revised Clean Air Act. Since the units are intermediate operated units, the ability to base load the units to reduce sulfur emissions even further is available at an incremental dispatch cost.

EXISTING AND PLANNED GENERATION

THE SOUTHERN COMPANY PURCHASES

On July 19, 1988, the Southern Company and Florida Power Corporation executed a contract that provides capacity sales from specified portions of coal-fired generating units owned by Alabama Power, Georgia Power, and Gulf Power. This unit power sale ("UPS") will be supplied from Units 1 through 4 of Alabama Power's Miller Plant and Unit 3 of the Scherer Plant jointly owned by Georgia Power and Gulf Power. The UPS is scheduled to commence on January 1, 1994 and continue through May 31, 2010 in the following amounts:

- 200 MW — January 1, 1994 - December 31, 1995
- 400 MW — January 1, 1995 - May 31, 2010

Florida Power Corporation has the right to terminate up to 200 MW of the unit power sale on or after January 1, 2000 upon a minimum of three years advance written notice. FPC also has an option to advance a portion of the unit power sale to January 1, 1993. The notice requirement in the UPS contract does not require FPC to make a commitment on the early option until 24 months prior to the need for capacity. This allows for the evaluation of the most cost-effective means of meeting the 1993 and 1994 need.

FPC also has the contractual option to make purchases from the Southern Company under its tariffed Long-Term Power Service, sometimes referred to as Schedule-E Power, in place of 1993 and 1994 unit power purchases. From FPC's standpoint, Schedule E power is almost equivalent to UPS purchased power during 1993 and 1994, except that the Schedule E demand charge is approximately one-half that of the UPS purchase. However, Schedule E is expected to have a high availability in this time frame. Accordingly, Florida Power has given notice of its intention to substitute 400 MW of Long-Term Power (Schedule-E) for its 1993 option period.

FPC has a similar option to substitute 200 MW of Schedule E purchases in place of the UPS early option during 1994. Although it has not been necessary to give notice of the exercise of this option to the Southern Company, FPC presently assumes that it will make this substitution. All of the alternatives studied as part of this determination reflect the maximum

EXISTING AND PLANNED GENERATION

contractually permissible Schedule E purchases. Figure 5.2 summarizes the assumed configuration of the Southern Company purchases. The decision for the early option period of 1994 will be made prior to the conclusion of 1991. However, for the purposes of this analysis, it was assumed that 200 MW of Schedule E power is also purchased in 1994.

The relatively low fixed cost and coal energy cost of this purchase, combined with the options described above, provides Florida Power with an economical and flexible resource alternative. The Southern UPS purchase was evaluated during the 1987-1988 Generation Facility Study and was determined to be competitive with other capacity alternatives that were available for the same time period.

ECONOMY PURCHASES

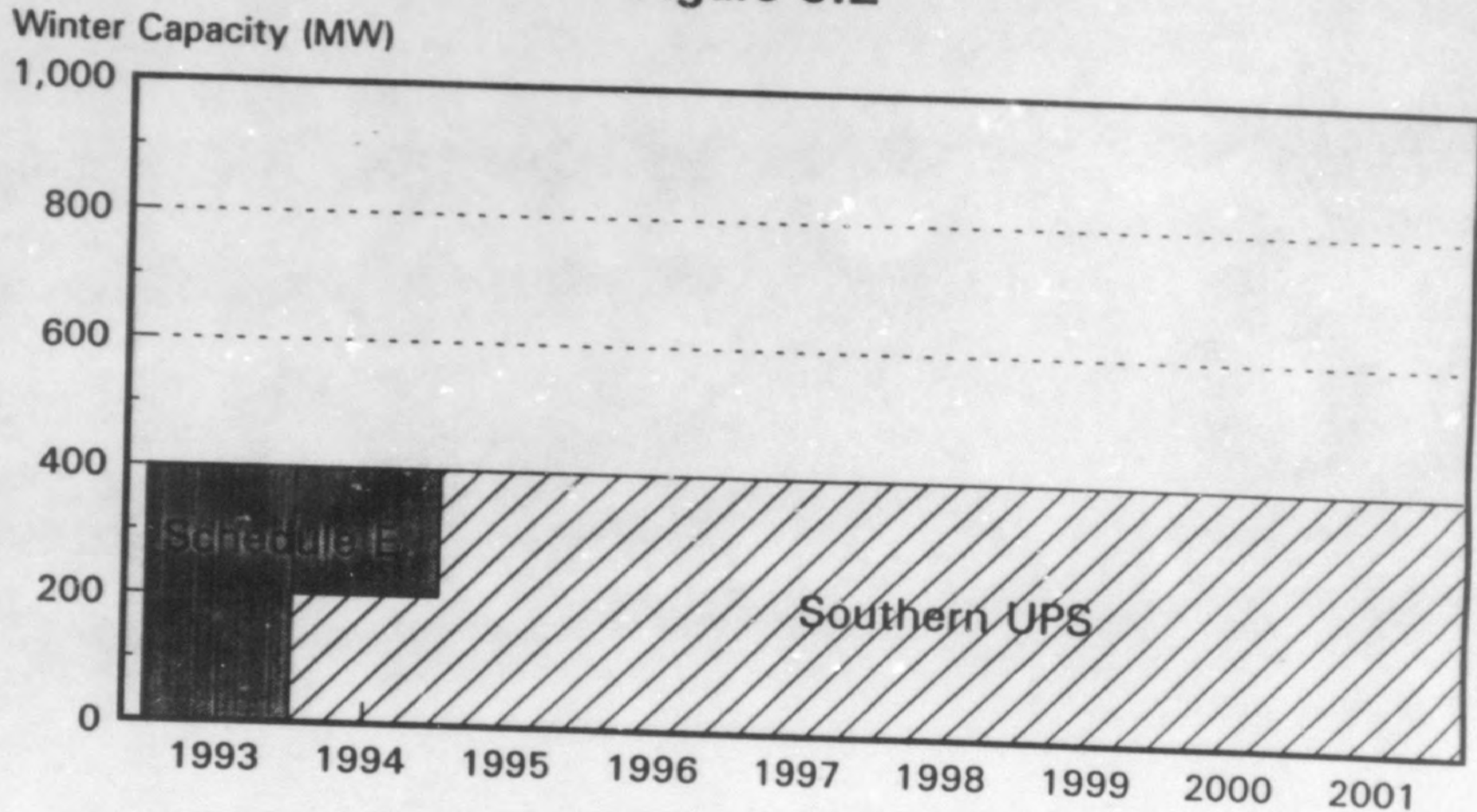
Opportunities to reduce system costs by engaging in nonfirm economy purchases are fully incorporated into FPC's economic analysis of demand and supply alternatives. Although economy purchases do not contribute to meeting FPC's capacity requirements, they make an important contribution towards serving FPC customers' energy needs at the lowest possible cost.

For the purposes of system planning, economy purchases are incorporated into FPC's economic analysis using production cost models. These models are designed to estimate the fuel cost of the FPC system, making full allowance for hourly nonfirm economy interchange that replaces high cost energy with lower cost energy from other utilities when the latter is available. Consistent with utility practices, the price paid by FPC for these purchases is estimated to be one-half the difference between the buyer's and seller's cost ("split-the-savings").

The projected amounts of economy energy available for purchase is based on a forecast by FPC's Energy Control Department. The current models estimate that approximately 900 GWh of economy energy will be purchased on the broker each year until the 500 kV line becomes operational in 1997. Upon completion of the 500 kV line, it is estimated that

Southern Company Purchases

Figure 5.2



EXISTING AND PLANNED GENERATION

economy purchases from the Southern Company will be approximately 1,000 GWh each year.

WEST COAST 500 KV EXPANSION

Florida Power Corporation is planning to construct, in association with Florida Power & Light, a 500 kV transmission line between Alabama Power's Farley Plant, and the Central Florida Substation to enter into service in 1997. This line will increase the ability of the Peninsular Florida electric system to exchange electricity with the larger interconnected grid to the north. The line is expected to increase the Florida interface transfer capability by a minimum of 1,300 MW. As presently planned, FPC's portion of the 1,300 MW transfer capability of the line is expected to be 65.4%, or approximately 850 MW.

Additional transmission serves a number of roles in the economics of utility system planning and operation. A stronger transmission system enhances reliability by allowing for increased emergency purchases during periods of high demand and unexpected outages. In these instances, the transmission line and the emergency purchases of generation are substitutes for the additional construction of peaking plants that might otherwise serve the unexpected gap between supply and demand.

When transmission lines are not used for emergency capacity, they are available for nonfirm economy purchases during all of the hours. The 500 kV line permits FPC to purchase as much as 2,600 GWh per year of economy energy over and above emergency purchases for reliability purposes.

In some cases, transmission lines are dedicated to the purchase of firm generating capacity located at the far end of the line. The configuration of the FPC system, along with the extremely low life-cycle cost of the four proposed combined cycle plants, indicates that FPC's portion of the 500 kV line is more valuable for emergency and economy purchases than it is for firm capacity purchases. When combined with the proposed combined cycle plants, the 500 kV line enables FPC to achieve a system configuration that provides reliable service to its customers at the lowest, long-run expected total cost.

EXISTING AND PLANNED GENERATION

SUMMARY

Tables 5.1 and 5.2 list all of the FPC existing, planned, and proposed units along with their winter net dependable MW rating and their scheduled operational date, if applicable. These plants, combined with FPC's DSM resources, additional transmission capability, and purchases from QFs and other utilities, provide the baseline for the evaluation of generation expansion alternatives. Figure 5.3 shows the total generation resources added from 1993 to 2001 by types. It indicates that there are approximately equal amount of generating capacity added from coal-based purchased power, natural-gas-fired combined cycles, and combustion turbines installed by 2001.

Existing, Planned, and Proposed Generating Facility Installations
Table 5.2

PLANT NAME	UNIT NO.	UNIT TYPE	FUEL TYPE		FUEL TRANSPORTATION		COMMERCIAL IN-SERVICE (MO/YR)	NET CAPABILITY (MW)		STATUS	NOTES
			PRIMARY	ALTERNATE	PRIMARY	ALTERNATE		SUMMER	WINTER		
DEBARY	P7-10	GT	F02		TK		Nov. 1992	304	364	U	1
INTER. CITY	P7-10	GT	F02		UN		Nov. 1993	304	364	P	1
UNIV. PROJECT	P1	GT	NG		PL		Nov. 1993	37	40	P	
UPS PURCHASE	1	ST	BIT		RR,TK,WA		Jan. 1994	200	200		
UPS PURCHASE	2	ST	BIT		RR,TK,WA		Jan. 1995	200	200	P	1
COMBINED CYCLE	1	CC	NG	F02	PL	UN	Nov. 1998	200	235	P	1
COMBINED CYCLE	2	CC	NG	F02	PL	UN	Nov. 1999	200	235	P	1
COMBINED CYCLE	3	CC	NG	F02	PL	UN	Nov. 1999	200	235	P	1
COMBINED CYCLE	4	CC	NG	F02	PL	UN	Nov. 2000	200	235	P	1
HIGGINS	1-3	ST	F06	NG	WA	PL	(Dec. 1999)	(119)	(123)	R	2
HIGGINS	P1-3	GT	F02	NG	WA	PL	(Dec. 1999)	(50)	(60)	R	2
HIGGINS	P3-4	GT	F02	NG	WA	PL	(Dec. 1999)	(50)	(66)	R	2
AVON PARK	P1-2	GT	F02	NG	TK	PL	(Dec. 2000)	(50)	(60)	R	2

LEGEND:**Generating Unit Type:**

ST - Steam Turbine - Non-Nuclear
 GT - Combustion Turbine
 CC - Combined Cycle

Fuel Type:

NG - Natural Gas
 F06 - No. 6 Fuel Oil
 F02 - No. 2 Fuel Oil
 BIT - Bituminous Coal

Fuel Transportation:

WA - Water
 TK - Truck
 RR - Railroad
 PL - Pipeline
 UN - Unknown

Status of Additions and Changes:

U - Under Construction.
 P - Planned, but not authorized.
 R - To be retired.

NOTES :

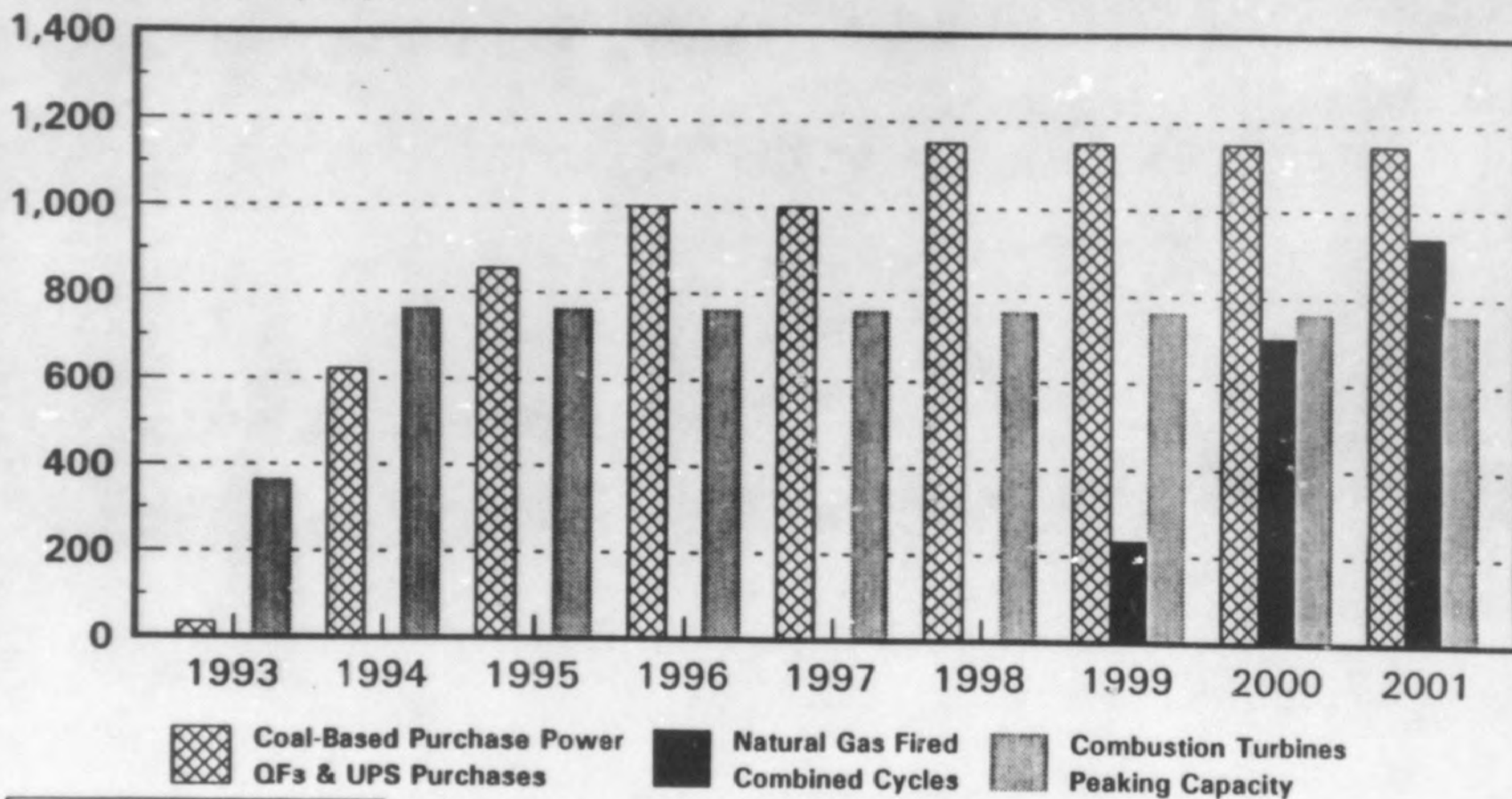
- (1) All capacity designated as commercial in November is to meet anticipated need beginning in January of the following year.
 (2) To be retired.

Generation Resource Additions

1993 - 2001

Figure 5.3

Cumulative Winter Capacity (MW)



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EXISTING AND PLANNED GENERATION

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Section 6: QUALIFYING FACILITIES IN THE PLANNING PROCESS

INTRODUCTION

Qualifying Facilities (QFs) constitute an integral part of FPC's supply-side resources. FPC has purchased more QF capacity than any other utility in Florida, and in fact, has purchased more QF capacity than all other Florida Investor-Owned Utilities (IOUs) combined. Figures 6.1 and 6.2 compare the QF capacity purchases by the state's four IOUs. FPC's Integrated Resource Planning Study shows that further purchases of generation from QFs, or any other source, are not in the best interest of Florida Power's customers.

The financial and other reasons why this is the case are discussed in Sections 9, 11, and 12. Section 6 describes the amount and type of QF resources presently under contract and projected to be added to the FPC system over the present planning horizon. The existence of these resources was assumed for the purposes of FPC's integrated resource plan.

QF CAPACITY, PRESENT AND PROJECTED

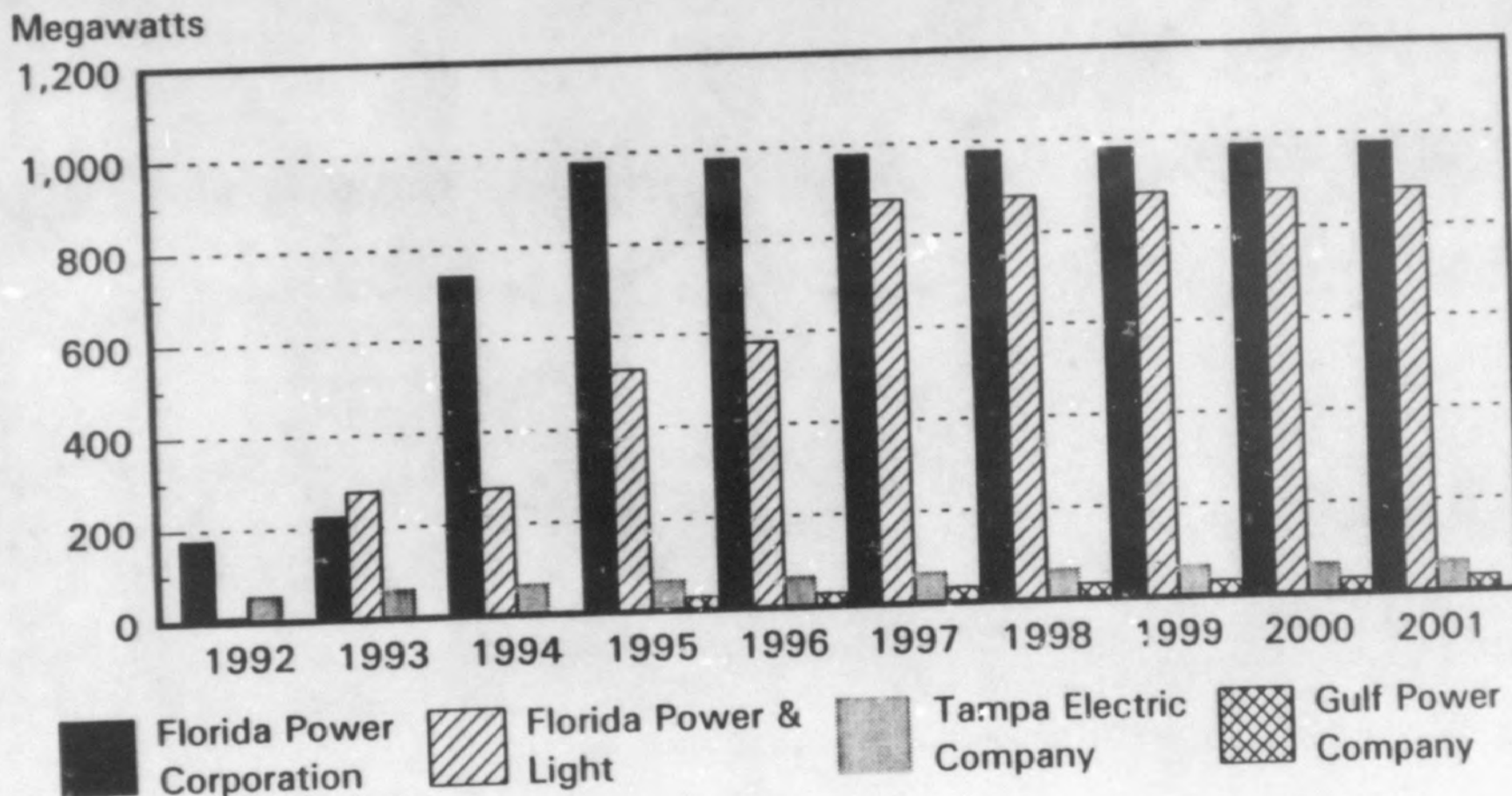
Cogenerators and small power producers (SPPs) are currently under contract to provide FPC with an additional 802 MW between 1992 and 1996. Should all of this additional capacity come on line, QFs will provide the FPC system with more than 1,000 MW of generating capacity in 1996, or more than 11% of the supply-side resources on the 1996 FPC system. This amount includes the 10 QF contracts totaling 642 MW that FPC entered into in the past year.

Florida Power will contract for an additional 150 MW of QF capacity planned to be in service in 1997. It is expected that the 150 MW increment will be comprised of 80 MW

Contracted Firm Capacity Purchases

From Qualifying Facilities in Florida

Figure 6.1

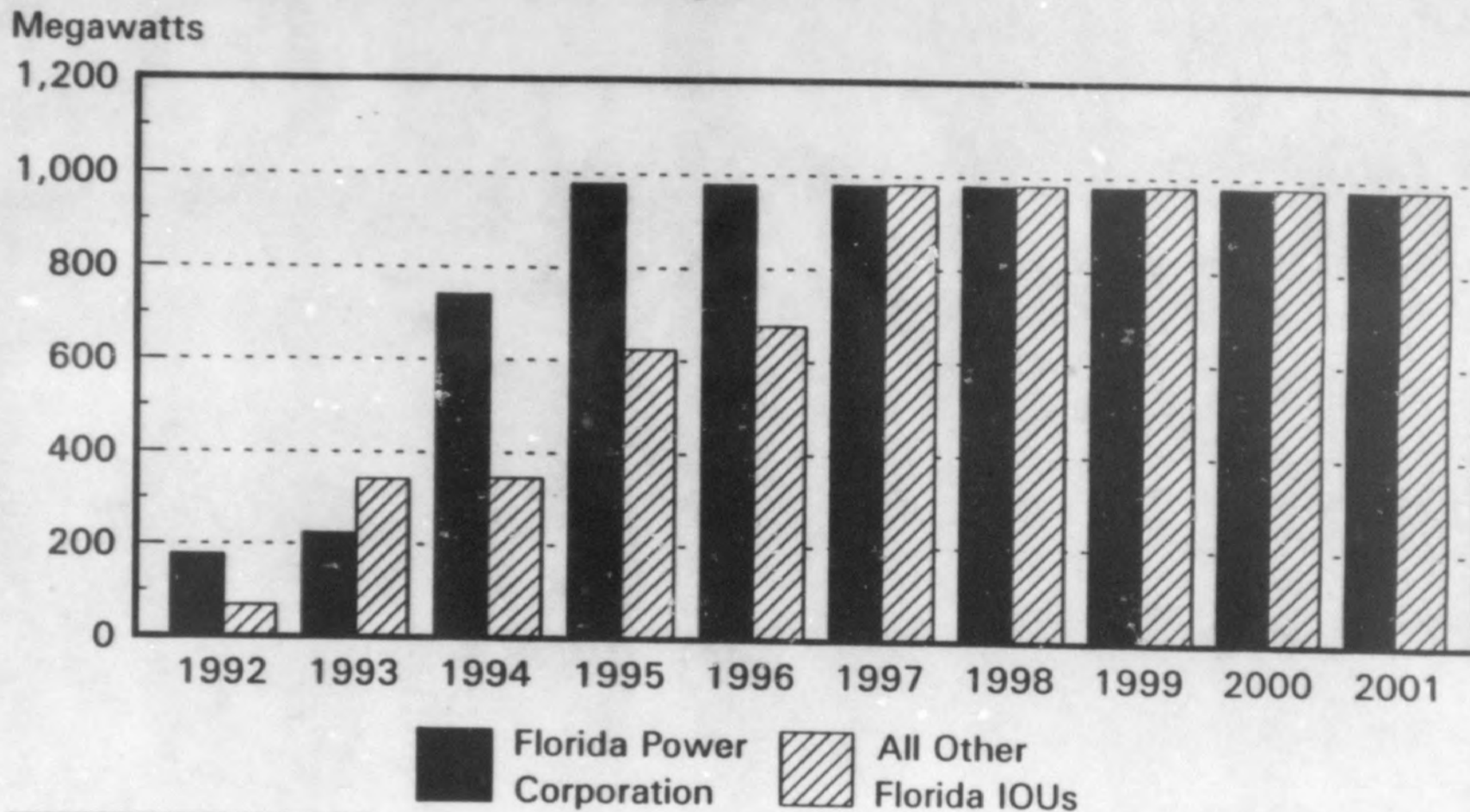


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Contracted Firm Capacity Purchases from QFs

FPC vs All Other Florida IOUs

Figure 6.2



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QUALIFYING FACILITIES IN THE PLANNING PROCESS

of standard offer contracts and 70 MW of negotiated contracts. No contracts for this 150 MW have been signed at this time. Table 6.1 lists all contracted and projected-to-be-contracted QFs on the FPC system. Existing facilities have both net and gross generating capacity listed, while future facilities list only contracted (net) generation.¹ Detailed information about each facility is provided in Appendix G, APH forms 6.4 through 6.7.

CATEGORIES OF QF PURCHASED CAPACITY

For the purposes of understanding the contribution of QFs to the FPC system, it is useful to group Florida Power's purchases into five category groups, as follows:

- Group I — Self-Service Cogeneration Units
- Group II — Existing QFs with Firm Contracts
- Group III — Future QFs Capacity Contracted for Under the "New" Rules
- Group IV — Future QFs Capacity Contracted for Under the "Old" Rules
- Group V — 1991 "Mini" APH Avoided Unit

Group I is comprised of QFs that provide only as-available energy to FPC. They sell to FPC on a tariff basis and have no specific sales contract. QFs in this group do not receive capacity payments.

In the aggregate, the QFs in Group I provide the equivalent of a maximum of 27 MW to FPC's system. This represents less than 1% of FPC's present peak load requirements.

¹Gross generation is the total generating capability of the plant's generator. Net generation is the amount of energy expected to be sold and delivered to the FPC system. The difference between gross and net generation consists of power generated and used by the QF inside its own facilities.

QUALIFYING FACILITIES IN THE PLANNING PROCESS

Group I
Self-Service Cogeneration Units
Table 6.1

Name	Unit	Fuel	In-Service	Generation Gross	Net (MW)
Ben Hill Griffin	1	Natural Gas	11/81	0.5	0.0
Buckeye Cellulose	1	Wood	1/54	35.0	0.0
Citrus World	1	Natural Gas	10/79	0.4	0.0
Citrus World	4	Natural Gas	12/87	4.0	4.0
Occidental Chemical	1	Waste Heat	1/37	18.0	4.0
Occidental Chemical	2	Waste Heat	5/86	28.0	8.0
St. Joe Forest Products	1	Wood	1/37	38.0	0.0
St. Joe Forest Products	2	Wood	7/83	3.0	3.0
USS AgriChem	1	Waste Heat	10/82	32.0	8.0
Total					27.0
Probability @ 100%					x1.0
Expected QF Capacity					27.0

#

QUALIFYING FACILITIES IN THE PLANNING PROCESS

Group III
Future QF Capacity Contracted for Under the "New" Rules
Table 6.1 (continued)

Name	Unit	Fuel	In-Service	Generation (MW)
Dade County Resource Recovery	1	Waste	11/91	43.0
EcoPeat	1	Peat	1/96	36.5
El Dorado Energy	1	Natural Gas	1/94	103.9
Lake Cogen Ltd.	1	Natural Gas	8/93	102.0
Mulberry Energy	1	Orimulsion	1/94	72.0
Orlando CoGen Ltd.	1	Natural Gas	1/94	72.0
Pasco Cogen Ltd.	1	Natural Gas	8/93	102.0
Ridge Generating Station	1	Biomass	1/94	36.0
Royster Phosphate	1	Waste Heat	12/93	28.0
Seminole Fertilizer	1	Waste Heat	10/92	47.0
Total				642.2
Probability @75%				x0.75
Expected QF Capacity				481.8

QUALIFYING FACILITIES IN THE PLANNING PROCESS

Group IV
Future QF Capacity Contracted for Under the "Old" Rules
Table 6.1 (continued)

Name	Unit	Fuel	In-Service	Generation (MW)
General Peat Resources	1	Peat	12/95	52.0
General Peat Resources	2	Peat	12/95	52.0
General Peat Resources	3	Peat	12/95	52.0
Pinellas County Resource Recovery	3	Waste	1/95	40.0
Timber Energy	2	Wood	1/95	6.0
Total				202.0
Probability @75%				x0.75
Expected QF Capacity				151.5

QUALIFYING FACILITIES IN THE PLANNING PROCESS

Group V
1991 "Mini" APH Avoided Unit
Table 6.1 (continued)

Name	Unit	Fuel	In-Service	Generation (MW)
Unidentified Units	-	unknown	1997	150.0
Probability @100%				x1.0
Expected QF Capacity				150.0

QUALIFYING FACILITIES IN THE PLANNING PROCESS

Group II consists of eight qualifying facilities with a total generating capacity of 135 MW.² All of these facilities have been completed and are in-service. These QFs have executed contracts with FPC that call for both capacity and energy payments. The Group II contracts were negotiated against a 1992 or 1995 statewide avoided unit. Some facilities currently receive capacity payments, while others will begin receiving capacity payments in the next few years. All of these receive as-available energy payments, which will continue until their contract energy payments begin in 1992 or 1995.

Group III consists of 10 facilities totaling 642 MW. All of these QFs have executed negotiated contracts with FPC, but none of these facilities has begun making sales. The first facility expected to provide capacity is the already-constructed Metro Dade Resource Recovery Plant. This facility is scheduled to provide 43 MW, wheeled through Florida Power & Light, beginning in November, 1991. All of the other units are contracted to come in-service by early 1994.

Group IV consists of units that comprise a block of QFs that are in the early development stages. The contracts for these seven units are priced similarly to those in Group II, i.e., their capacity and energy payments are based on the 1992 or 1995 statewide avoided unit. The capacity under contract from Group IV units totals 202 MW. Two units contracted with Corporation for Future Resources (CFR) are excluded from Group IV. These contracts were under dispute at the time this Study was created.

Finally, Group V consists of a block of capacity and energy that Florida Power Corporation proposed in the 1991 "Mini" Annual Planning Hearing (APH) to purchase from QFs in place of construction of 150 MW of combustion turbine capacity in 1997. Of this, 80 MW will be purchased under Standard Offer contracts and 70 MW will be negotiated. As these units have not been individually identified or contracted for at this time, Group V is shown as a single line item in Table 6.1.

²Lake County Resource Recovery is currently contracted to provide 10.3 MW to FPC. Since this facility came on line in September 1990, it has consistently provided 12 MW to the grid. Therefore, the facility is modeled at 12 MW since there is no indication that the plant output will decrease in the future.

QUALIFYING FACILITIES IN THE PLANNING PROCESS

ACCOUNTING FOR QF COMPLETION UNCERTAINTY

If a source of purchased capacity is still in the developmental stages, there is always uncertainty as to whether it will become operational as planned. For example, Seminole Fertilizer exercised their contract option to lower capacity from 47 MW to 15 MW. This reduction occurred at a date too late to be captured in this Study, which assumed 47 MW for the Seminole Fertilizer contract. Florida Power is also aware that many proposed QF projects are abandoned during the developmental process.

FPC has elected to account for the uncertainty associated with QF projects by contracting for more capacity than it presently believes is needed. It is difficult to know how much additional QF capacity should be placed under contract, as information and experience with QFs is limited. FPC has elected to contract for approximately 25% more capacity than reliability studies indicates is required. This percentage was recently reviewed by the Commission when it approved the contracts comprising Group III. Virginia Power recently has also used this percentage in making QF acquisition decisions.

The additional 25% produces a contracting goal of approximately 655 MW of additional capacity in Group III. The Group III total of 642 MW closely approximates this target. Group IV projects were likewise discounted by 25%. Therefore, 633.3 MW, which is 75% of the cumulative totals of Groups III and IV, was used in all planning reliability studies. FPC's capacity and energy payments were also scaled down accordingly for planning purposes.

QUALIFYING FACILITIES IN THE PLANNING PROCESS

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Section 7:

FORMULATION OF ALTERNATIVE PLANS

INTRODUCTION

The first stages in the development of a cost-effective resource plan consist of developing and assembling economic and other assumptions, producing the load forecast, obtaining information on existing and planned resources, and producing a maximum-attainable-DSM plan. These operations permit the analysis to advance to the next stage, which is the formulation of alternative generation expansion plans.

The formulation of alternative generation plans is a multifaceted exercise in which the multitude of theoretically possible generation expansion options is reduced to a realistic, analyzable set of alternatives. Each of the alternatives must satisfy a number of criteria and constraints. As a minimum, each alternative must:

1. Utilize technologies that are likely to provide reliable, long-lasting, cost-effective generation;
2. Represent a size and schedule configuration that provides for the continued reliability of the FPC system under expected loads;
3. Permit the FPC system to meet all environmental and emissions requirements, including constraints imposed by the revised Clean Air Act; and
4. Represent an alternative that meets a number of systemwide economic and strategic objectives (for example, flexibility with respect to changes in load growth).

This section discusses the formulation of 10 alternative expansion plans that meet these criteria and constraints. Each of these alternatives represents a generic alternative in the sense that, with very minor modifications, a large family of related sub-alternatives can be examined using electric utility system planning procedures.

FORMULATION OF ALTERNATIVE PLANS

The remainder of this section discusses the procedures that led to the 10 core alternatives examined by FPC. The criteria and constraints are discussed in the following subsections.

TECHNOLOGY PRESCREENING

The first criterion in the development of generation expansion alternatives involves the identification of generic generation technologies whose technical and cost characteristics cause them to be worthwhile candidates for inclusion in full-fledged alternative plans. The basis for selecting these technological "building blocks" is a prescreening process that examines the characteristics of available generating technologies and selects candidate technologies based on this information.

The primary criteria for including a technology in FPC's planning process are technical maturity and operational flexibility. The technical maturity of a process relates to the degree to which the technology has been demonstrated in utility applications. In general, a commercial-scale demonstration unit must have been built and operated before this criteria is fully met.

Operational flexibility refers to the likelihood that the technology can be applied to meeting FPC's generation requirements in a manner that: 1) is likely to be cost effective, given current economic projections; and 2) permits the FPC system to continue to operate in an integrated, efficient manner. For example, if a particular technology was low in cost but not suitable for FPC's load characteristics that technology would not be useful to the FPC system at this time. To fully examine the issue of operational flexibility, it is necessary to factor into account the size, fuel type, construction requirements, and ability to match the technology to the service it must perform.

Once a technology meets these criteria, it is considered to be a legitimate capacity alternative and is included in the planning process. To make this determination, FPC maintains an ongoing assessment program that examines established, innovative, and developing generating technologies. Through active involvement with the Electric Power Research Institute, vendor contacts, professional societies, and architect/engineering presentations, as well as the

FORMULATION OF ALTERNATIVE PLANS

ongoing review of the trade and professional literature, FPC keeps abreast of technological advancements and available generation options.

An established foundation of feasible technology options is maintained and periodically updated to keep current with market conditions. The subsection titled "Results of PreScreening" summarizes the five technologies emerging from FPC's assessment process at the time of this generation expansion study. FPC used the following technologies as its primary technology choices.

- Combustion Turbines
- Combined Cycle Units
- Pulverized Coal Plants
- Integrated Gasification Combined Cycle
- Fluidized Bed Plants

Results of Prescreening

Based on FPC's ongoing technical assessment program, the prescreening of technologies for the study time frame produced these generic candidate technologies:

- **Combustion Turbine**
 - Combustion turbines have been proven as an economic option for peaking capacity as a result of decades of commercial operating experience. In recent years, materials development have allowed combustion turbine designers to significantly improve both output and efficiency. These advancements have expanded the role of combustion turbines to include mid-range service in both simple and combined cycle modes. The primary features of a combustion turbine are its low construction cost, short lead time, rapid start, load control capability, and fuel flexibility.
 - This technology was evaluated in 40 and 165 MW (winter rating) capacity sizes, using natural gas or distillate fuel.

FORMULATION OF ALTERNATIVE PLANS

- **Combined Cycle**

- Like the combustion turbine, the combined cycle unit is proven through years of operational experience. The interrelations between the combustion turbine and steam cycle provide a significant improvement in efficiency over either cycle alone. Although higher in installed cost than a simple cycle combustion turbine, the combined cycle unit can be built for about half the cost of a pulverized coal plant. The primary advantages of combined cycle technology are operational flexibility, moderate construction time, and fuel diversity.
- This technology was evaluated as a capacity size of 235 MW (winter rating), using natural gas or distillate fuel.

- **Pulverized Coal**

- The pulverized coal unit (PC) is a well proven generating option. It provides the majority of energy for many electrical systems, including Florida Power Corporation. Coal is both plentiful and relatively inexpensive. However, the construction of a pulverized coal unit is more expensive and time consuming when compared to the other options. For the purpose of this study, the proposed units were assumed to use Eastern bituminous coal. A 1% sulfur coal similar to the coal consumed at Crystal River South was assumed.
- Significant postcombustion cleanup systems must now be used on the modern PC unit in order to meet environmental regulations. This equipment increases both construction and operating costs, decreases cycle efficiency, and results in the generation of more solid waste byproduct.
- This technology was evaluated in two capacity sizes, 450 and 700 MW (winter rating), based on a reference design similar to Crystal River 4 and 5 with the addition of a scrubber.

FORMULATION OF ALTERNATIVE PLANS

- **Integrated Gasification Combined Cycle**

- Integrated gasification combined cycle (IGCC) is a relatively new addition to FPC's list of viable generating technologies. Demonstration projects by the three major domestic suppliers (Texaco, Dow, and Shell) over the past decade have adequately proven gasification technology for use in the electric power industry. This study evaluates IGCC using two different fuel sources — high sulfur coal and orimulsion. Orimulsion is an inexpensive Venezuelan crude oil with a enormous available reserve. The Orimulsion option (OGCC) included advanced technology designed to gasify low grade fuel oils.
- The primary advantages of IGCC are its use of low cost/grade fuels, its high efficiency, and its environmental cleanliness. Like combustion turbines and combined cycles, IGCC can be built in capacity sizes that are compatible with FPC's annual load growth. Of all the technologies considered in this study, coal gasification is one of the more expensive to build. However, orimulsion gasification involves less processing equipment and therefore can be built for a lower cost than coal gasification.
- This technology was evaluated for two capacity sizes for coal, 290 MW and 580 MW (winter rating), and one capacity size for orimulsion, 593 MW (winter rating).

- **Fluidized Bed**

- Atmospheric fluidized bed combustion technology provides coal capacity at relatively high capital cost with environmental benefits similar to a scrubbed coal unit. Like IGCC, fluidized bed technology is a relatively new addition to FPC's list of feasible generating options. Fluidized bed projects built during the 1980s that are now operating have proven that this technology is suitable for utility application. While the fluid bed boiler can handle a wide variety of solid fuel feedstocks, low quality coal is likely to be the most common. This technology has the advantage of low emissions without the use of postcombustion cleanup systems. However, like

FORMULATION OF ALTERNATIVE PLANS

the pulverized coal unit, it is expensive and time consuming to build, moderately efficient, and produces significant waste streams.

- This technology was evaluated as a capacity rating of 150 MW (winter rating), using higher sulfur coal.

CHARACTERISTICS AND COSTS OF PRESCREENED TECHNOLOGIES

During the early stages of the planning process, it is commonly recognized that design-specific technical and cost data do not exist. It is therefore common to treat technology options on a generic, conceptual basis. Considerable judgment is used when estimating the cost and performance characteristics of technology types. Rather than base estimates on a single design configuration, FPC takes a broader view and establishes values that are representative of the group as a whole.

The assumptions related to the technologies used in the alternative capacity models were received from the Generation Technology group within Florida Power Corporation. Consistent with its technology assessment activities, Generation Technology develops conceptual cost and performance data on:

- Unit design and construction costs,
- Preproduction capitalized cost,
- Operating and maintenance expenses,
- Unit heat rate, and
- Unit availability.

Table 7.1 summarizes key components of these data for the successful candidate technologies. A comparison of the capital costs in 1991 dollars excluding AFUDC for the generation technologies used in this study is shown in Figure 7.1. Appendix D provides a more complete description of the conceptual costs and performance data for the same generic technology options.

Assumptions : Supply – Side Options – 1991 Facility Plan
(1991 Dollars)

Table 7.1

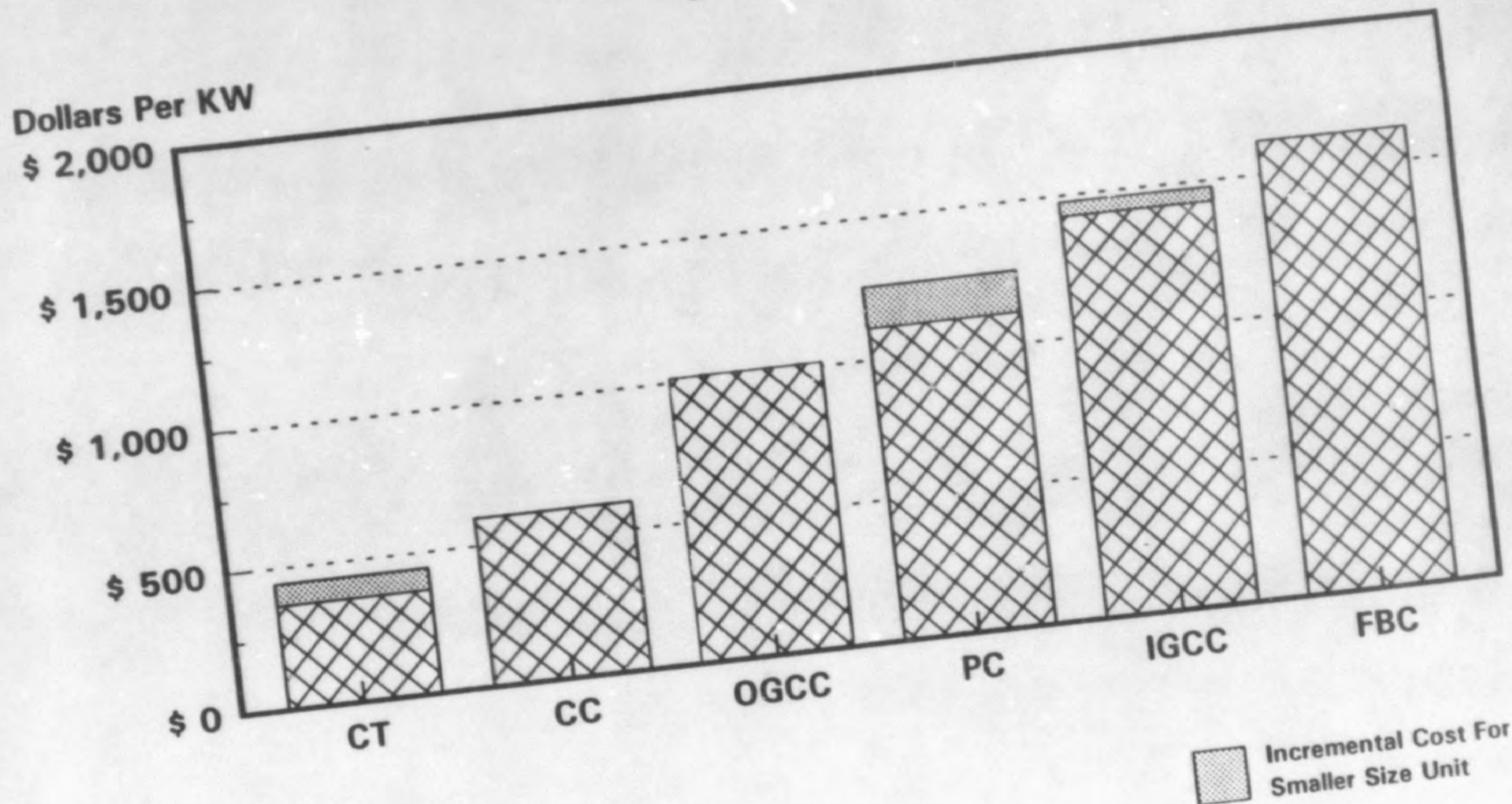
Technology	Winter (MW)	Capital (\$/ KW)	Fixed O&M (\$/ KW –YR)	Variable O & M (\$/ MWH)	Heat Rate (BTU/ KWH)	Schedule Maintenance	Forced Outage
Pulverized Coal : Large	700	1,112	\$14.89	\$4.58	9,650	8%	5%
Pulverized Coal : Small	450	1,254	\$21.77	\$4.58	9,650	8%	5%
Fluidized Bed : Coal	150	1,615	\$40.92	\$5.25	9,650	10%	7%
IGCC : Large	580	1,423	\$24.90	\$3.43	8,965	5%	10%
IGCC : Large	290	1,473	\$27.00	\$3.75	8,965	5%	10%
OGCC (Net with Oxygen Plant)	537	1,012	\$30.59	\$3.56	8,062	5%	6%
Combined Cycle on Gas	235	599	\$5.49	\$2.29	7,960	5%	4%
Combined Cycle on Distillate	235	599	\$5.49	\$2.29	7,786	5%	5%
Combustion Turbine on Gas : Large	165	370	\$6.18	\$1.83	12,040	5%	2%
Combustion Turbine on Gas : Small	40	444	\$7.50	\$2.50	9,187	2%	3%
Combustion Turbine on Distillate : Large	165	370	\$6.18	\$1.83	11,497	5%	4%

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Capital Costs For Generation Technologies

In 1991 Dollars Without AFUDC

Figure 7.1



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FORMULATION OF ALTERNATIVE PLANS

RELIABILITY ASSESSMENT

The second criterion that must be applied to generation expansion alternatives relates to the maintenance of system reliability. For the purposes of system planning, FPC maintains two reliability standards:

- The FPC system must attain 0.1 days per year assisted Loss of Load Probability (LOLP); and
- The FPC system must possess a 15% winter reserve margin.

All fully qualified generation expansion alternatives must continuously satisfy both of these standards. In other words, a proper generation expansion alternative must contain prescreened technologies sized and scheduled so as to closely adhere to, and not fall below, these minimum reliability standards.

The combination of a LOLP and a reserve margin standard is the ideal combination of reliability criteria for a utility with FPC's load shape. The LOLP standard best captures the probabilistic nature of power system operations and generator forced outages, as well as tie line assistance and daily load variations. It is generally accepted throughout the utility industry and by the Florida Public Service Commission.

The reserve margin criterion provides a measure of the utility's ability to serve winter peaks on an isolated system basis. It is necessary to maintain an adequate reserve margin, as well as to have an acceptable LOLP. Adequate reserve margins assist in maintaining flexibility if planning assumptions change and prevent an overreliance on assistance from neighboring utilities. They also provide operating reserves for the multiple loss of large units, unusual weather patterns, temporary shifts in customer usage patterns, unanticipated changes in growth rates and other unexpected developments.

FPC has revised its reserve margin standard for this and all future planning and operation activities. Prior to this study, FPC used a winter reserve margin criterion of 10%. After a

FORMULATION OF ALTERNATIVE PLANS

review of reserve margin criteria used by other utilities, both within and outside of Florida, a 15% reserve margin was considered a reasonable planning criterion.

FPC plans and operates its system in coordination with neighboring utilities, thus enabling the realization of mutual economic and reliability benefits. FPC has interchange agreements in effect with 25 electric systems in Florida and the Southeast, as shown in Appendix C. These systems are interwoven with a complex transmission grid. The FPC portion of this grid consists of over 4,300 miles of transmission line and 75 transmission and plant substations. Operating voltages of the FPC transmission system include 500 kV, 230 kV, 115 kV, and 69 kV. The State of Florida Electric System Map, included in this document as Figure 7.2, displays all of the interconnections between Florida utilities.

Florida Power Corporation measures LOLP, the first standard, using the Tie Line Assistance and Generation Reliability (TIGER) program. FPC's model of assistance available from the utilities that interconnect to it was revised in mid-1990 in the TIGER reliability program. In studies prior to 1990, the area to be modeled, or the "assistance area," included the rest of Peninsular Florida and the Southern Company (SOU), as shown in Figure 7.3. One of the characteristics of this model is that the transfer limit between Peninsular Florida and the Southern Company is not captured. The model assumes that the transfer between utilities within the assistance area is unconstrained.

In Figure 7.3, the solid arrow shows the transfer of 400 MW between FPC and Southern. This 400 MW of UPS power is purchased from the Southern Company and totally commits the available transfer capability between the utilities. The broken arrow shows the uncommitted tie line capacity between FPC and the other Florida utilities. This level was 2,000 MW prior to 1989 and 2,500 MW for 1989 studies. FPC's old model viewed the interconnections with other utilities at the total tie line capability. However, the transmission system cannot be reliably operated at this level. In addition, it was recognized that the rest of Peninsular Florida alone could not provide the level of assistance, 2,000 or 2,500 MW, that the tie line capability indicated. Therefore, the model was changed to reflect the First Contingency Total Transfer Capability (FCTTC) import limit for the FPC system, which is calculated by FPC's Transmission and Distribution Planning Department using load flow calculations. The FCTTC calculated was to be 1,200 MW with Peninsular Florida in 1990.

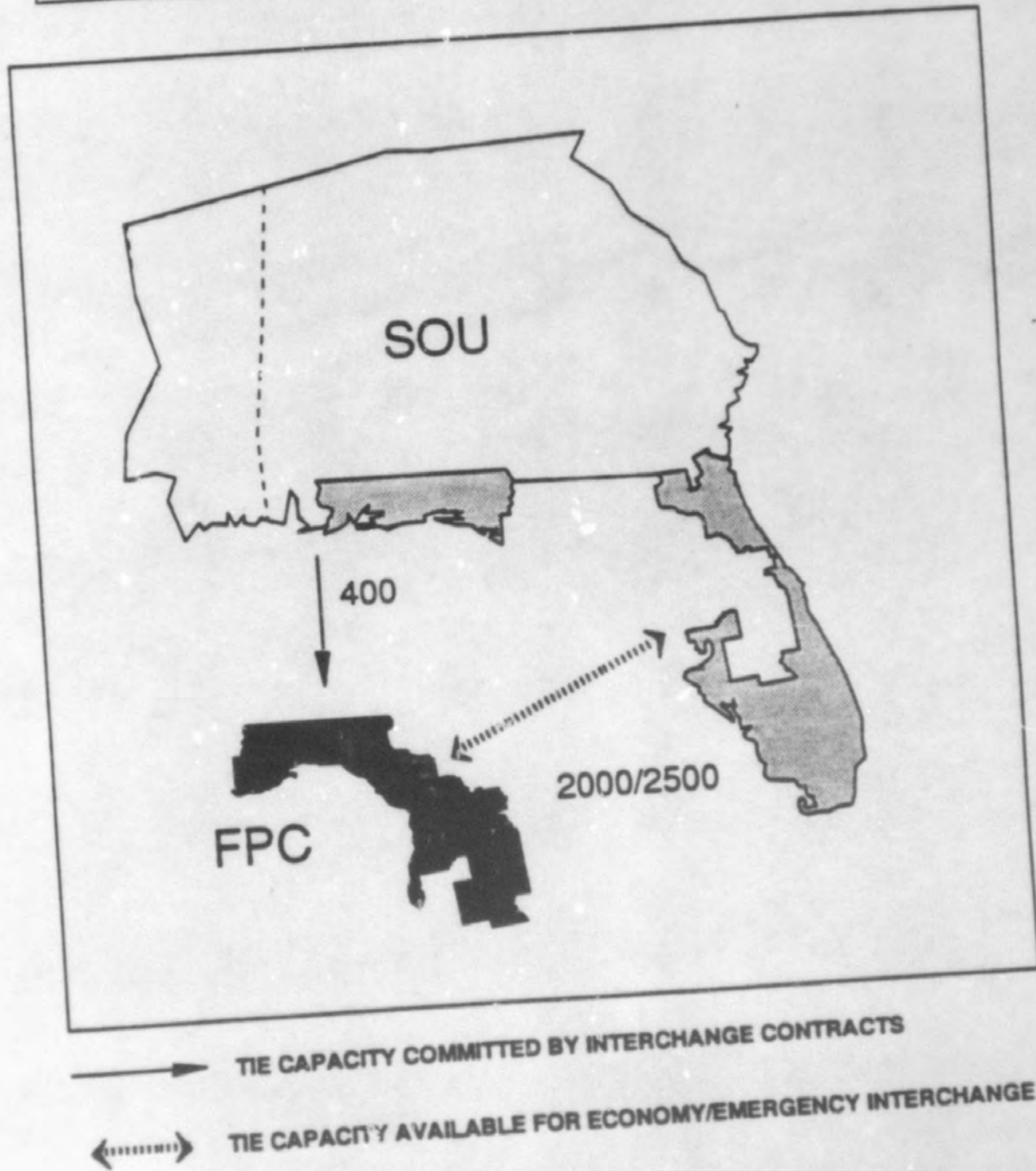
FORMULATION OF ALTERNATIVE PLANS

Figure 7.2

(Please see Key Map at the back of this Study.)

Figure 7.3

**FLORIDA POWER CORPORATION
ASSISTANCE AREA MODEL FOR TIGER
1989 AND PRIOR STUDIES**



FORMULATION OF ALTERNATIVE PLANS

FPC determined that the model used in studies prior to 1990, with the Southern Company as part of the assistance area, overstates the assistance available to the primary area (FPC). The new model, which has been used in all studies since 1990, restricts the assistance area only to Peninsular Florida, which is depicted in Figure 7.4. The Southern Company is modeled as two capacity injections, one into the primary area (FPC) and one into the assistance area (Peninsular Florida). The FCTTC between the Southern Company and Peninsular Florida in 1996, before the addition of the third 500 kV tie line, is 3,400 MW. This value is increased from the 3,200 MW used currently due to facility additions throughout the state system.

In Figure 7.4, the 400 MW of committed transfer capability between the Southern Company and FPC is shown as a solid arrow. The 3,000 MW FCTTC between the Southern Company and the assistance area is divided into two parts. The solid arrow represents 2,100 MW of committed tie line capability between the two areas. The broken arrow represents 900 MW of tie line capacity that is available for emergency assistance.

With the construction of the third 500 KV tie line from Florida to the Southern Company system, the FCTTC to Florida will be increased by 1,300 MW, to 4,900 MW. Existing facilities will account for 3,600 MW of transfer capability, and the new 500 kV line accounts for 1,300 MW. For reliability purposes, FPC uses 500 MW of its tie line capacity, as shown in Figure 7.5. The capacity injected into the Peninsular Florida assistance area then increases by 800 MW. In addition, the FPC tie capacity to the Florida assistance area will increase to 2,200 MW. This is due to the new 500 kV, as well as other facility additions throughout the FPC system. These improvements are currently scheduled to be in service by January 1997.

In contrast to the complex art of LOLP measurement, the calculation of winter reserve margin is straightforward. Generation expansion alternatives must be configured so that the installed firm capacity at the assumed time of the winter system peak (January) exceeds the corresponding system peak load by at least 15% of that load.

Figure 7.4

**FLORIDA POWER CORPORATION
ASSISTANCE AREA MODEL FOR TIGER
BEFORE ADDITION OF THIRD 500kV TIE LINE**

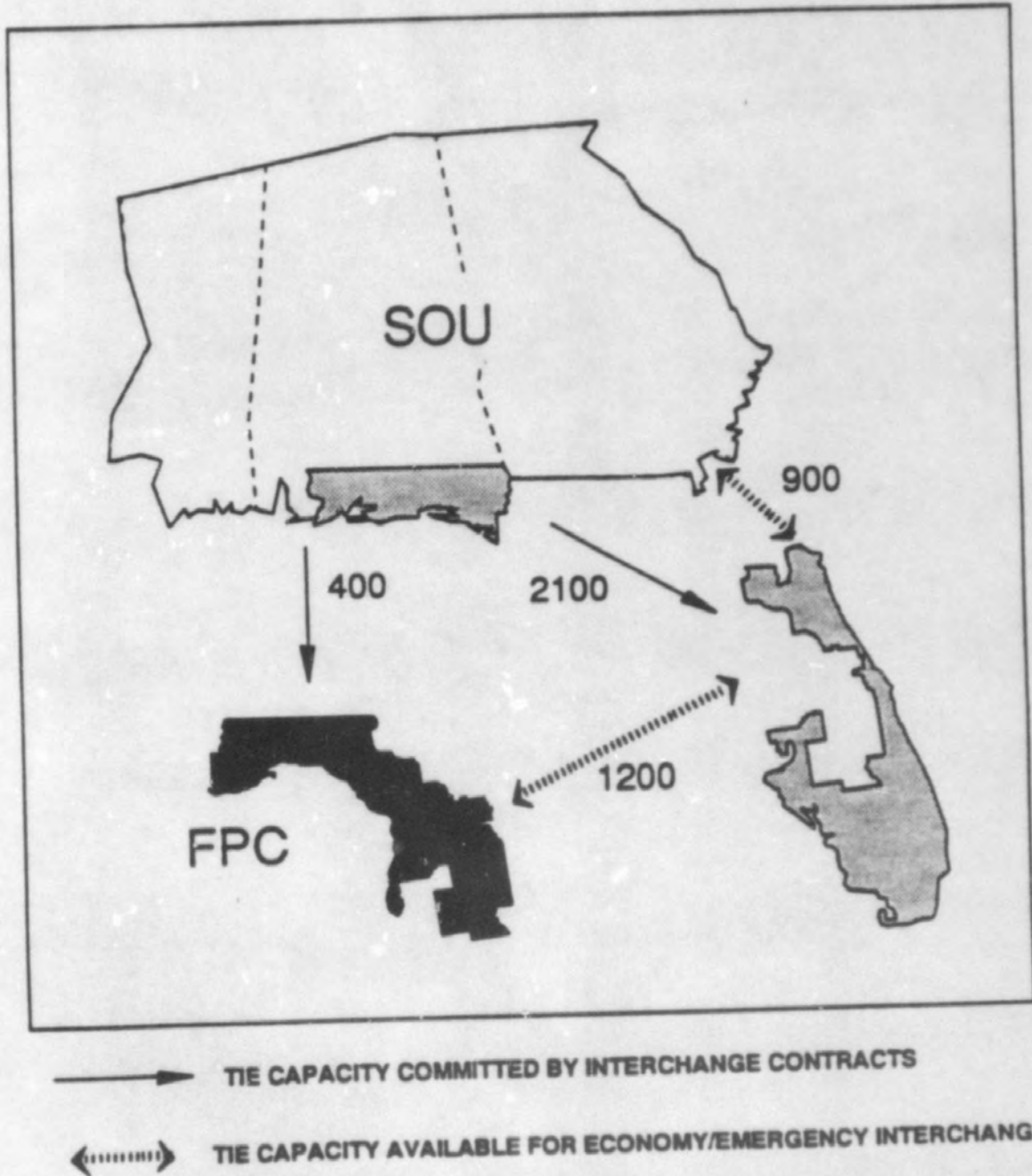
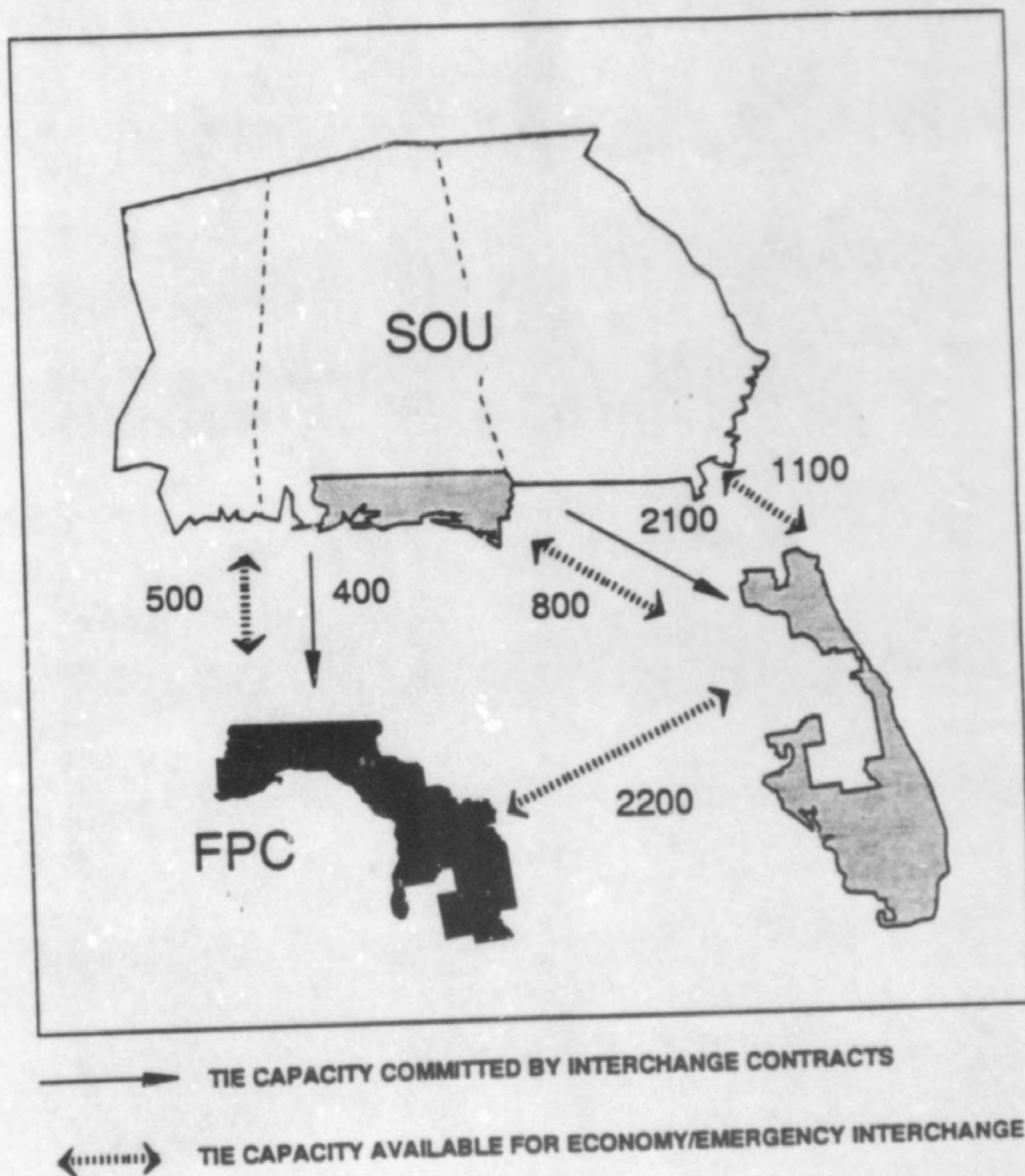


Figure 7.5

**FLORIDA POWER CORPORATION
ASSISTANCE AREA MODEL FOR TIGER
AFTER ADDITION OF THIRD TIE LINE**



FORMULATION OF ALTERNATIVE PLANS

The 10 alternatives developed for this planning study each meet both the LOLP and reserve margin standards. Appendix E displays the load and capacity statements that underlie the reserve margin calculations in each year of the study. Calculations made using the TIGER program indicate that the 10 alternatives also satisfy the FPC LOLP standard, as shown in Appendix E, Table LOLP-1.

CLEAN AIR ACT

Title IV of the Clean Air Act Amendments was signed into law on November 15, 1990. This law will have a significant impact on the planning and operation of all electric utilities. Florida Power Corporation has included the requirements of this legislation into the planning process.

The revised act will be implemented in two phases. Phase I will take effect in 1995 and limit the emissions of specific units with very high rates of sulfur dioxide (SO_2) emissions. Florida Power Corporation does not have any units that will be affected by the requirements of Phase I. The intent of Phase II is to limit the electric utility industry to a limit of 8.9 million tons of SO_2 emissions each year beginning in the year 2000. Each utility will receive a systemwide number of allowances. An "allowance" is equal to one ton of SO_2 emissions. In Phase II, each utility will be required to hold as many allowances as its units will require each year.

The final allocation of allowances by the Environmental Protection Agency (EPA) has not been completed. As the rule-making procedure has been evolving, Florida Power Corporation's estimates of the allowances it will receive has varied between 125,000 to 135,000 tons. The planning estimate of 130,000 tons is therefore a reasonable target for planning purposes. The Phase II requirement will take effect in the year 2000.

FORMULATION OF ALTERNATIVE PLANS

CLEAN AIR ACT PLANNING ASSUMPTIONS

The final rules and regulations to implement the amendments to the Clean Air Act have not been completed. However, reasonable assumptions about these rules can be made to insure that a long-term resource plan will comply with the law. The major assumptions regarding the Clean Air Act are summarized below.

- The total number of Florida Power Corporation's SO₂ allowances is estimated at 130,000. This number of allowances was derived from an estimate of the basic allowance rate plus an estimate of bonus and growth allowances. The basic allowance was based on Florida Power Corporation's historical SO₂ emission rates with a reduction due to the EPA's reserve and the nationwide limit of 8.9 million tons. The final rules will determine FPC's exact number of emission allowances.
- Florida Power Corporation may obtain additional SO₂ allowances due to its extensive conservation and DSM programs. These allowances are not specifically modeled since the allocation of these allowances has not been made final.
- The Clean Air Act excludes existing combustion turbines from the systemwide SO₂ limit calculation. Operation of the existing combustion turbines at Avon Park, Debary, Bayboro, Bartow, Higgins, Intercession City, Turner, Port St. Joe, Rio Pinar, and Suwannee do not require the use of emission allowances.
- The emission allowances allocated to Florida Power Corporation are to be used on a systemwide basis. There are no restrictions on individual units.
- Phase II limitations are expected to take effect beginning in January 2000.
- The economic value of emission credits is presently unclear. For the purposes of this Study, the Resource Plan must not exceed FPC's expected number of emission credits. The trading or banking of emission credits are assumed to be a short-term solution to specific operating problems, such as the failure of a major unit or an interruption of a fuel supply.

FORMULATION OF ALTERNATIVE PLANS

- Any power purchased by Florida Power Corporation is assumed to be accompanied by its own emission allowances. The cost of those allowances is to be included in the price of power sold to FPC.

The inclusion of the restrictions of the Clean Air Act in the planning process requires the integration of traditional expansion planning with the constraint of SO₂ emissions. In the course of producing workable alternatives to be considered, several principles regarding systemwide compliance became apparent.

- The application of an emission control strategy does not always produce an intuitive result. Due to the economic dispatch of system units, the emission improvements on one unit can cause it to operate at a higher dispatch cost, and a less clean unit may become more economical. The clean unit then runs less, the less-clean unit runs more, and total system emissions are not lowered as expected.
- The economic dispatch of units is an important contributor to lower emissions. If a unit is not dispatchable, it has the potential to raise system emissions due to the operation of other units on the system.
- The total system emissions are highly dependent upon the Demand and Energy Forecast. The load shape and total energy requirements can vary the annual SO₂ emission significantly.
- The fuel price forecast can affect emissions if there is a significant cost difference between the price of high sulfur fuels and low sulfur fuels. If the system is operated most economically, it will tend to use the less expensive, dirty fuel.
- The addition of emissions control equipment on existing units can lower the MW capacity and the reliability of the unit. These detriments cause the need for additional capacity to maintain an equivalent system reliability. In addition, an alternative that requires the addition of emissions control equipment on existing plants must bear the cost of those improvements with no capacity improvements.

FORMULATION OF ALTERNATIVE PLANS

METHODS OF EMISSIONS COMPLIANCE

Florida Power considered a variety of techniques to comply with the SO₂ limits imposed by the Clean Air Act. The methods of compliance had to be technically feasible and cost effective. The results showed that the following strategies were effective methods of reducing SO₂ emissions.

- Install emissions control equipment (scrubbers) on existing or new units to reduce stack emissions. The control equipment was assumed to reduce SO₂ emissions by 95%.
- Replace higher sulfur content fuels with lower sulfur content fuels (fuel switching). The conversion of units to natural gas or constructing units to burn natural gas can eliminate the SO₂ emissions on those units.
- Construct units using newer technology that can burn high sulfur fuels with a very low rate of SO₂ emissions. Integrated gas combined cycle (IGCC) units, fluidized bed coal plants, or pulverized coal plants with very efficient scrubbers are examples of these technologies.
- Make power purchases to reduce the use of existing units. A power purchase does not truly eliminate emissions, since it transfers the responsibility of obtaining the allowance to the seller of the energy. However, a power purchase is an option that can be considered as a method of complying to a systemwide SO₂ limit.

COMPLIANCE STRATEGIES OF ALTERNATIVES

In order to serve as a realistic planning alternative, each generation expansion plan had to be modified to meet FPC's expected SO₂ emissions limit. Usually, the addition of clean base load or intermediate load capacity run on economic dispatch, will reduce the FPC's systemwide SO₂ emissions enough to meet the allowance limit. In all cases, except for Alternative 4, this could be accomplished by switching to lower sulfur content fuels at the Bartow Plant and at the Crystal River 1 and 2 units. When Alternative 4 was considered,

FORMULATION OF ALTERNATIVE PLANS

combined cycle units burning distillate oil, the addition of scrubbers on the Crystal River Units 4 and 5 was required, along with fuel switching at the Barton plant. The possibilities for compliance also could include fuel switching at the Anclote Plant. Depending on the availability of natural gas at that site, the conversion of Anclote Plant to burn natural gas is a viable fuel switching option.

Table 7.2 lists the 10 major alternatives considered in this study and the emissions strategy necessary to insure Clean Air Act compliance. The total systemwide SO₂ emissions before taking corrective action (the "emission fix") is shown under the heading "SO₂ No Fix." After the corrective action, total systemwide emissions are shown under the heading "With Fix." This table shows that all of the alternatives considered had total system emissions below 130,000 tons in the year 2000. In addition, all of the alternatives have a margin of safety below 130,000 tons to allow for variations in unit operation, variations in the demand and energy forecast, and possible changes in the total number of allowances allocated to FPC.

In summary, the major elements of the emissions compliance are:

- Allowance = 1 ton of SO₂ emissions;
- National Limit = 8.9 million tons/year in 2000;
- FPC estimated allowance = 130,000 tons/year in 2000; and
- FPC expected SO₂ emissions in year 2000 is approximately 122,300 tons based on Alternative 3 — four natural-gas-fired combined cycle units.

FORMULATING ALTERNATIVE PLANS

The final criterion to be met during the formation of alternative plans relates to a number of system considerations that help determine the usefulness and cost-effectiveness of a particular plan. These considerations include the following:

Clean Air Act Compliance Strategies for Alternatives

Table 7.2

Alternative	Comments	1997	1998	1999	2000	MW Capacity	Emission Fix	SO2 No Fix/ With Fix
1	PC - Large	OUC-110	2CTD-165	PC-700		1030	Fuel Switch Bartow/CR1&2	151,653 / 120,136 Tons
2	PC - Small		2CTD-165	PC-450	CTD-165	945	Fuel Switch Bartow/CR1&2	159,573 / 126,613 Tons
3	CC - Gas		CCG-235	2CCG-235	CCG-235	940	Fuel Switch Bartow/CR1&2	154,353 / 122,332 Tons
4	CC - Distillate		CCD-235	2CCD-235	CCD-235	940	Scrub CR4&5, Switch Bartow	171,875 / 107,495 Tons
5	CT - Gas - Small		6SCTG-40	10SCTG-40	8SCTG-40	960	Fuel Switch Bartow/CR1&2	165,047 / 126,171 Tons
6	OUC Purchase/CC-Gas		CCG-235	2CCG-235	CCG-235	1050	Fuel Switch Bartow/CR1&2	151,700 / 119,221 Tons
7	IGCC		CTD-165	IGCC-580	IGCC-290	1035	Fuel Switch Bartow/CR1&2	151,114 / 120,211 Tons
8	Fluidized Bed		CTD-165	3FBC-150	2FBC-150	915	Fuel Switch Bartow/CR1&2	157,231 / 125,070 Tons
9	OGCC		OGCC-593		2CTD-165	923	Fuel Switch Bartow/CR1&2	151,938 / 122,590 Tons
10	Purchase PC - Small		PU-PC-376	CCG-235	2CTG-165	941	Fuel Switch Bartow/CR1&2	155,885 / 123,077 Tons

LEGEND:

PC - Pulverized Coal
 CCG - Combined Cycle on Gas
 CCD - Combined Cycle on Distillate
 SCTG - Small Combustion Turbine on Gas
 CTG - Large Combustion Turbine on Gas
 CTD - Large Combustion Turbine on Distillate
 IGCC - Integrated Gasification Combined Cycle on Coal
 FBC - Fluidized Bed Combustion on Coal
 OUC - Orlando Utilities Temporary Coal Purchase
 OGCC - Orimulsion Gasification Combined Cycle
 PU-PC - Purchase Pulverized Coal - UPS

All in-service dates are November 1.

of units precede unit description.

Unit Winter MW capacity follows unit description.

Integrated Resource Study

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NOTES:

Phase II takes effect in the year 2000

Emission fixes are implemented Jan. 1, 2000

Values of "No Fix" are for 1999

Values of "With Fix" are for 2000

Expected FPC allowance allocation = 130,000 tons

Alternative #3 is the recommended plan

FORMULATION OF ALTERNATIVE PLANS

- **Schedule Flexibility and Modularity.** Ideally, expansion alternatives permit the acceleration or deceleration of the option in order to accommodate the inevitable differences between forecasted and actual load growth. Generally, alternatives with several smaller units and/or shorter construction schedules provide greater planning flexibility.
- **Fuel Diversity.** Larger amounts of fuel diversity provide a utility system with greater insurance against unanticipated fuel price increases in any one fuel. If an alternative increases the diversity of fuel sources, it increases the level of diversification or "insurance."
- **Type of Generation and System Needs.** Different diurnal and seasonal load patterns create different utility needs for peaking, intermediate, and cycling units. Generation alternatives will match these utility needs with differing levels of technical and cost effectiveness. Dispatchability, ramp rates, and other technical characteristics must also be considered in this evaluation.
- **Technological Innovation and Reliability.** Alternative plans may utilize technologies that range from well-proven methods that show little chance of improvement, and to newer, riskier methods that may provide improved performance. Alternative plans must balance these competing considerations.

In addition to incorporating FPC's technology prescreening, reliability standards, and Clean Air Compliance needs, FPC assembled 10 alternative expansion plans that factored these system considerations into account.

Base, intermediate, and peaking capabilities were evaluated along with various fuel supplies, such as coal, coal derived syn-gas, oil, and natural gas. Each alternative was evaluated based on system capacity needs, lead time of construction, construction benefits, technical and economical flexibility, overall capacity needs, economy of scale, mix of generation, mix of fuel and environmental regulations.

FORMULATION OF ALTERNATIVE PLANS

The complex, multifaceted series of evaluations described in this section produced 10 alternative expansion plans. These plans represent a broad spectrum of unit types, construction schedules, fuel sources, and procurement options. In the context of the decision analysis framework used to evaluate these 10 alternatives, FPC believes that they represent the 10 general types of alternatives likely to be the most cost-effective alternative for serving the needs of its customers in the year 1997 and beyond. The 10 alternatives are summarized in Table 7.3 and are more completely described below.

Alternative 1 — Large Pulverized Coal

Alternative 1 consists of the following units:

- 330 MW of Distillate Combustion Turbines in 1998, and
- 700 MW from a Pulverized Coal Plant in 1999.

This type of generation expansion alternative has been historically very attractive for low fuel cost but tends to have a high initial capital requirement. The flexibility in this alternative is reduced due to the long lead time of the coal unit. This type of unit allows for little flexibility in changes to customer growth. Lead time and system requirements cause the coal unit to be needed in the year 1999. To produce a configuration that matches Florida Power Corporation's needs, this alternative competes with a combination of a large traditional pulverized coal unit as base load capacity and two distillate combustion turbine units as peaking capacity. The pulverized coal unit would be equipped with scrubbers for clean air.

Alternative 2 — Small Pulverized Coal

Alternative 2 consists of the following units:

- 330 MW of Combustion Turbines in 1998,
- 450 MW from a Pulverized Coal Plant in 1999, and
- 165 MW of Combustion Turbines in 2000.

Ten Proposed Alternatives

Table 7.3

Alternative	Comments	1997	1998	1999	2000	MW Capacity	Description
1	PC - Large	OUC-110	2CTD-165	PC-700	CTD-165	1030	Economy of scale, secure fuel, long lead time
2	PC - Small		2CTD-165	PC-450	CCG-235	945	Secure fuel, long lead time, base & peak cap.
3	CC - Gas		CCG-235	2CCG-235	CCD-235	940	Gas available, spread capacity to meet reserve margin (RIM)
4	CC - Distillate		CCD-235	2CCD-235	CCD-235	940	Gas NOT available, spread capacity to meet RIM
5	CT - Gas - Small		6SCTG-40	10SCTG-40	8SCTG-40	960	Gas available, low capital to meet RIM
6	OUC Purchase/CC-Gas		CCG-235	2CCG-235	CCG-235	1050	OUC coal purchase, CC & CT on gas
7	IGCC		CTD-165	IGCC-580	IGCC-290	1035	New tech., inexp. fuel, economy of scale, CT for RIM
8	Fluidized Bed		CTD-165	3FBC-150	2FBC-150	915	New technology, inexpensive fuel
9	OGCC		OGCC-593	2CTD-165	2CTD-165	923	New tech., very inexp. fuel, economy of scale, CT for RIM
10	Purchase PC - Small		PU-PC-376	CCG-235	2CTG-165	941	Short lead time, UPS, wheel cost, low capital, CT for RIM

LEGEND:

PC - Pulverized Coal
 CCG - Combined Cycle on Gas
 CCD - Combined Cycle on Distillate
 SCTG - Small Combustion Turbine on Gas
 CTG - Large Combustion Turbine on Gas
 CTD - Large Combustion Turbine on Distillate
 IGCC - Integrated Gasification Combined Cycle on Coal
 FBC - Fluidized Bed Combustion on Coal
 OUC - Orlando Utilities Temporary Coal Purchase
 OGCC - Orimulsion Gasification Combined Cycle
 PU-PC - Purchase Pulverized Coal - UPS
 All in-service dates are November 1.
 # of units precede unit description.
 Unit Winter MW capacity follows unit description.

NOTES:

Winter MW Capacity used for Reserve Margin shown in table above.

FORMULATION OF ALTERNATIVE PLANS

This alternative is similar to Alternative 1 except that it reduces the amount of the high capital cost, base load portion of the coal unit and replaces it with peaking capability. This alternative relies more on the existing FPC base load generation, with additional peaking for reserve margins.

Alternative 3 — Combined Cycle on Gas

Alternative 3 consists of the following units:

- 235 MW of a Combined Cycle on Gas (CCG) in 1998,
- Another 470 MW of CCG in 1999, and
- 235 MW of a CCG to be built in 2000.

This alternative combines the flexibility of combined cycle technology with the efficiencies of a base load unit. The use of natural gas as the fuel supply provides for an environmentally clean fuel. The ability to match the customer load growth at a relatively low capital cost enables this alternative to be very flexible. The combined cycle units are spread out to meet the load growth as it occurs.

Alternative 4 — Combined Cycle on Distillate

Alternative 4 consists of the following units:

- 235 MW of Combined Cycle on Distillate (CCD) in 1998,
- Another 470 MW of CCD in 1999, and
- 235 MW of CCD in 2000.

As in Alternative 3, this alternative is very flexible, although natural gas is replaced with distillate. Distillate operations have typically been reserved for peak duty, except for a combined cycle operation where the increased efficiency can allow for slightly more operations. This alternative generally assumes that the existing FPC system has enough base load generation.

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Alternative 5 — Small Combustion Turbines

Alternative 5 consists of the following units:

- Six units of Small Combustion Turbines on Gas (SCTG), at 40 MW each, in 1998,
- Ten units of SCTG for 1999 (400 MW), and
- Eight units of SCTG for 2000 (320 MW).

Alternative 5 contains the new, high efficiency combustion turbine units with very low heat rates and low capital costs. Low unit MW ratings require multiple units to be installed, which provides excellent flexibility in meeting load growth. The unit's natural gas fuel source takes advantage of the excellent heat rate.

Alternative 6 — Orlando Utilities Commission (OUC) Purchase and Combined Cycle on Gas

Alternative 6 consists of the following units:

- The 110 MW purchase from Orlando Utilities in 1997,
- 235 MW of Combined Cycle on Gas (CCG) in 1998,
- Another 470 MW of CCG in 1999, and
- 235 MW of CCG in 2000.

This alternative is equivalent to Alternative 3 except it takes advantage of the Orlando Utilities short-term offer of base load coal capacity. OUC has 110 MW of coal energy available for seven years, starting in 1997. With the increasing load growth seen on the FPC system, the construction schedule of the combined cycle units in Alternative 3 is not altered for a short-term energy purchase.

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Alternative 7 — Integrated Gasification Combined Cycle (IGCC) - Coal

Alternative 7 emphasizes IGCC technology and consists of:

- A Combustion Turbine on Distillate (165 MW) in 1998,
- 580 MW of IGCC in 1999, and
- Another 290 MW of IGCC in 2000.

This alternative evaluates the use of coal gasification technology as clean base load capacity. Coal gasification is relatively new for the utility industry. Although it is only available at a high capital cost, it produces clean syn-gas on-site from inexpensive low grade coal. In addition, this alternative provides all of the operational flexibility of the standard combined cycle unit.

This alternative is expected to resemble the traditional large pulverized coal alternative from the standpoint of system economics. The smaller capacity increments of the gasification technology allow for more flexibility in meeting load growth. A large and small gasification plant enables base load generation to be spread out in years 1999 and 2000, respectively.

Alternative 8 — Fluidized Bed

Alternative 8 focuses on fluidized bed technology and includes the following plants:

- A Combustion Turbine on Distillate in 1998 (165 MW),
- 450 MW from Fluidized Bed in 1999, and
- Another 300 MW from Fluidized Bed in 2000.

This alternative evaluates the rising technological benefits of the smaller capacity sized coal units. Although fluidized bed technology is relatively high in capital cost, the ability to add 150 MW base load coal units and use inexpensive low grade coal supplies is its primary advantage. This alternative provides coal capacity that can be matched to load growth versus the economy of scale coal units as in Alternative 1.

FORMULATION OF ALTERNATIVE PLANS

Alternative 9 — Integrated Gasification Combined Cycle - Orimulsion

Alternative 9 also utilizes IGCC technology and contains:

- 593 MW of Orimulsion Gasification Combined Cycle in 1998, and
- Two Combustion Turbines on Distillate in 2000 (330 MW).

This alternative is similar to Alternative 7, except that it will employ a less expensive fuel known as orimulsion, a low grade crude oil from Venezuela. This orimulsion oil is used as a gasification fuel feed stock in a separate processing step prior to combustion. This would be a new and unique application. The high capital and O&M cost of this technology, coupled with very low projected energy costs, provides a potentially viable alternative for FPC.

Alternative 10 — Purchased Power

Alternative 10 includes the following:

- Purchased Pulverized Coal at 400 MW in 1998,
- A Combined Cycle on Gas at 235 MW in 1999, and
- Two Combustion Turbines on Gas, at 165 MW each, in 2000.

As a tenth alternative, Florida Power Corporation felt that an alternative revolving around a purchase of capacity from outside the state or from the northern part of the state should be considered.³ As a proxy for many possible purchases, Alternative 10 specifically examined a 400 MW purchase from a coal-fired plant offered by the Cajun Electric Cooperative in Louisiana. Due to line losses, the net received by FPC is 376 MW. To represent a complete alternative, this base load option was joined with a combined cycle plant and two combustion turbines in 1999 and 2000, respectively. The Cajun Electric offer of up to 400 MW of coal price capacity represents the lowest, reasonable offer being proposed to Florida Power. The major benefits of purchasing from Cajun Power is its low

³ Alternative 6 considers a short-term purchase of capacity from the central portion of the state.

FORMULATION OF ALTERNATIVE PLANS

energy cost. Other benefits include the certain availability of the plant (the unit is already on line) and an absence of in-state environmental impacts.

This alternative would provide an opportunity to mix low cost base load energy with the flexibility of intermediate combined cycle units and peaking units on natural gas. It is likely that the demand charges, plus wheeling and transmission costs of receiving energy through FPC's interface, could be competitive compared to the capital cost of building new Florida Power Corporation plants.

The 10 alternative plans describe above were evaluated by FPC for their respective economic advantages. This evaluation is discussed in Section 8.

FORMULATION OF ALTERNATIVE PLANS

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Section 8:

ECONOMIC AND RISK ANALYSIS

INTRODUCTION

Decision analysis acknowledges that complex decisions such as the selection of the most cost-effective resource expansion plan are not simple yes/no decisions. Rather, the economic value of an alternative is a combination of the most likely value of the alternative, i.e., its average or *expected* value, and the wide variety of upside and downside risks that significantly affect the economics of the plan.

FPC's use of decision analysis in the economic evaluation of the 10 alternative plans accounts for these complexities in several ways. The analysis is not limited to the most likely or expected value of an alternative. Although expected present value revenue requirements are an essential benchmark for the evaluation process, FPC's analysis also considered the *time path* of required revenues and the *riskiness* of the alternative to changes in economic or system parameters that change the value of the plan.

In brief, the purpose of FPC's decision analysis framework is to test each alternative plan under a variety of circumstances to see how sensitive the plan is to changes in key economic and system variables that cannot be forecast with absolute certainty. To account for uncertainty, each key variable that affects the economic value of the alternative is separated into several *scenarios*. Each of these scenarios is assigned a probability of "coming true" based on FPC's current information, judgment, and experience. When the decision analysis is complete, it is possible to estimate how likely it will be that the economic value of the alternative will be greater than or less than its expected value.

Another advantage of decision analysis is that it allows utility planners to determine the sensitivity of an alternative's value to one or more assumptions.

For example, an alternative may be found to be very sensitive to the fuel price forecast. When the multiple scenarios are run with this alternative, the sensitivity to the fuel forecast will become apparent. This particular alternative, when compared to an alternative that is

ECONOMIC AND RISK ANALYSIS

less sensitive to fuel prices, will be shown to have a higher "risk" to fuel pricing. Thus, the fuel sensitive alternative may be rejected because of this risk. This approach ensures that the expansion plan that is selected is not only best under the median case (or "most likely") forecast, but it also likely to be a good plan if there are unforeseen changes in the input assumptions.

DECISION ANALYSIS METHODOLOGY

The first step in a decision analysis is to determine the key variables that are subject to uncertainty and likely to have a significant impact on the economics of the 10 alternative plans. In this Study, the Fuel Forecast, Demand and Energy Forecast, and capital cost of technologies were identified as the parameters that greatly affect the present value of each alternative.

The uncertainty in each of these key inputs is represented by high, medium, and low forecasts. Each forecast has an associated probability of occurrence. Table 8.1 shows the likelihood of the key variable forecasts in the high, medium and low scenarios. Economically speaking, forecasts of fuel prices and the demand for power are interrelated. As a consequence, the fuel price and peak load/energy sales variables are typically grouped into consistent composite scenarios.

With uncertainties in the price of fuel, electricity demand, and the capital cost of the generating technologies in the alternative plans, a total of 27 ($3 \times 3 \times 3 = 27$) individual scenarios were developed to test each alternative plan. The development of the 27 scenarios and their associated probabilities are shown in Figure 8.1. The interrelation of the probabilities of fuel prices with demand and energy forecasts can be seen from this figure.

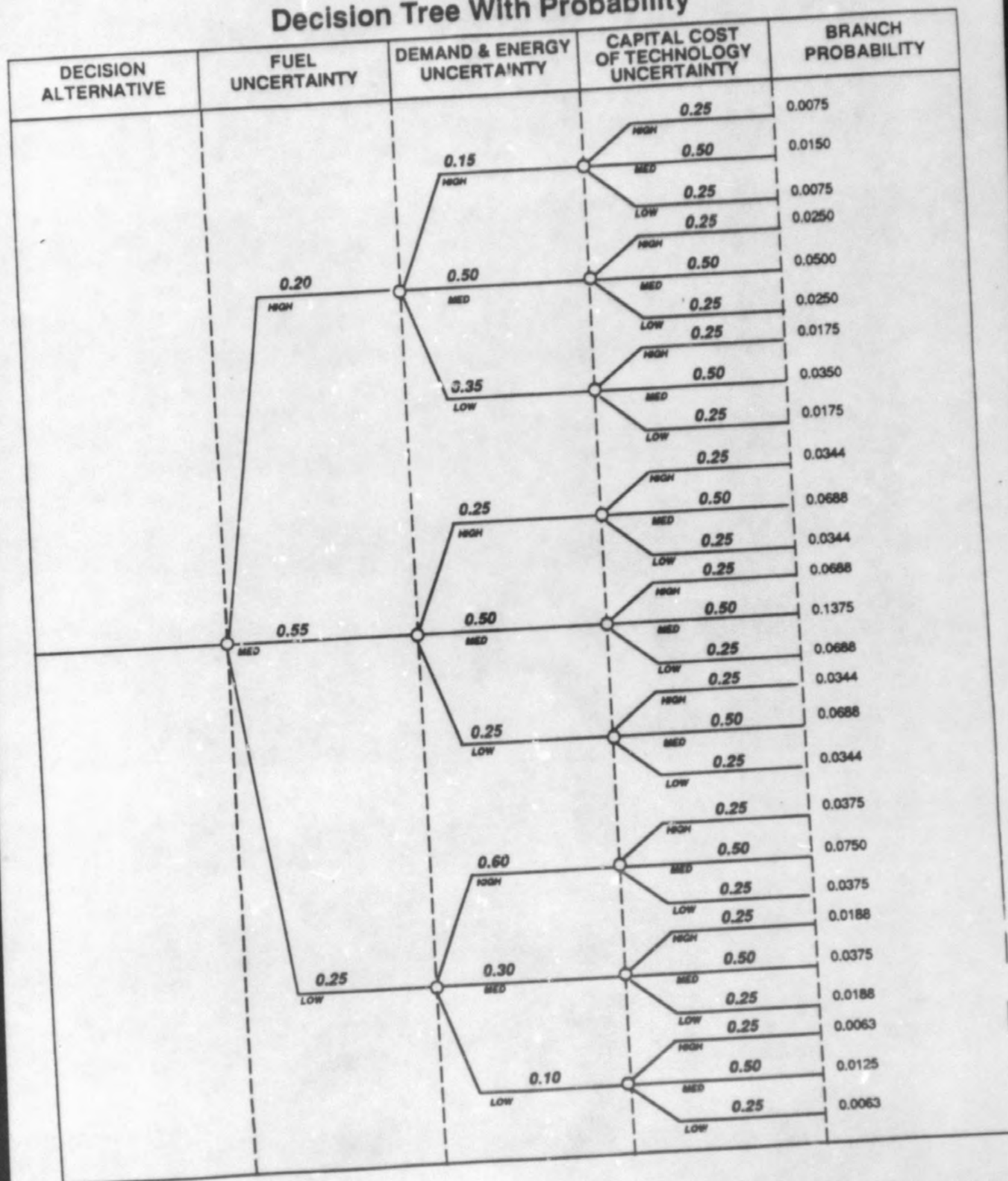
Florida Power uses the PROSCREEN II model to support Florida Power's decision analysis and resource planning. PROSCREEN II allows the evaluation of alternative plans to be done

ECONOMIC AND RISK ANALYSIS

Likelihood of Key Assumptions
Table 8.1

	Outcome		
	High	Medium	Low
Fuel Prices	20%	55%	25%
Demand and Energy (Normal Weather)	25%	50%	25%
Capital Cost of Technologies	25%	50%	25%

Figure 8.1
Decision Tree With Probability



ECONOMIC AND RISK ANALYSIS

in sufficient depth and with a high degree of accuracy. The model includes accurate production cost simulations, as well as accurate financial analysis. The PROSCREEN II system is connected to the PROMOD III production costing system to insure consistency in the results.

The primary output of the PROSCREEN II simulations is the revenue requirements necessary to support a given alternative. The annual revenue requirements are accumulated, and their present worth values are compared to those of other alternatives. Comparisons of the total CPWRR show the estimated cost differences to the rate payers between alternatives.

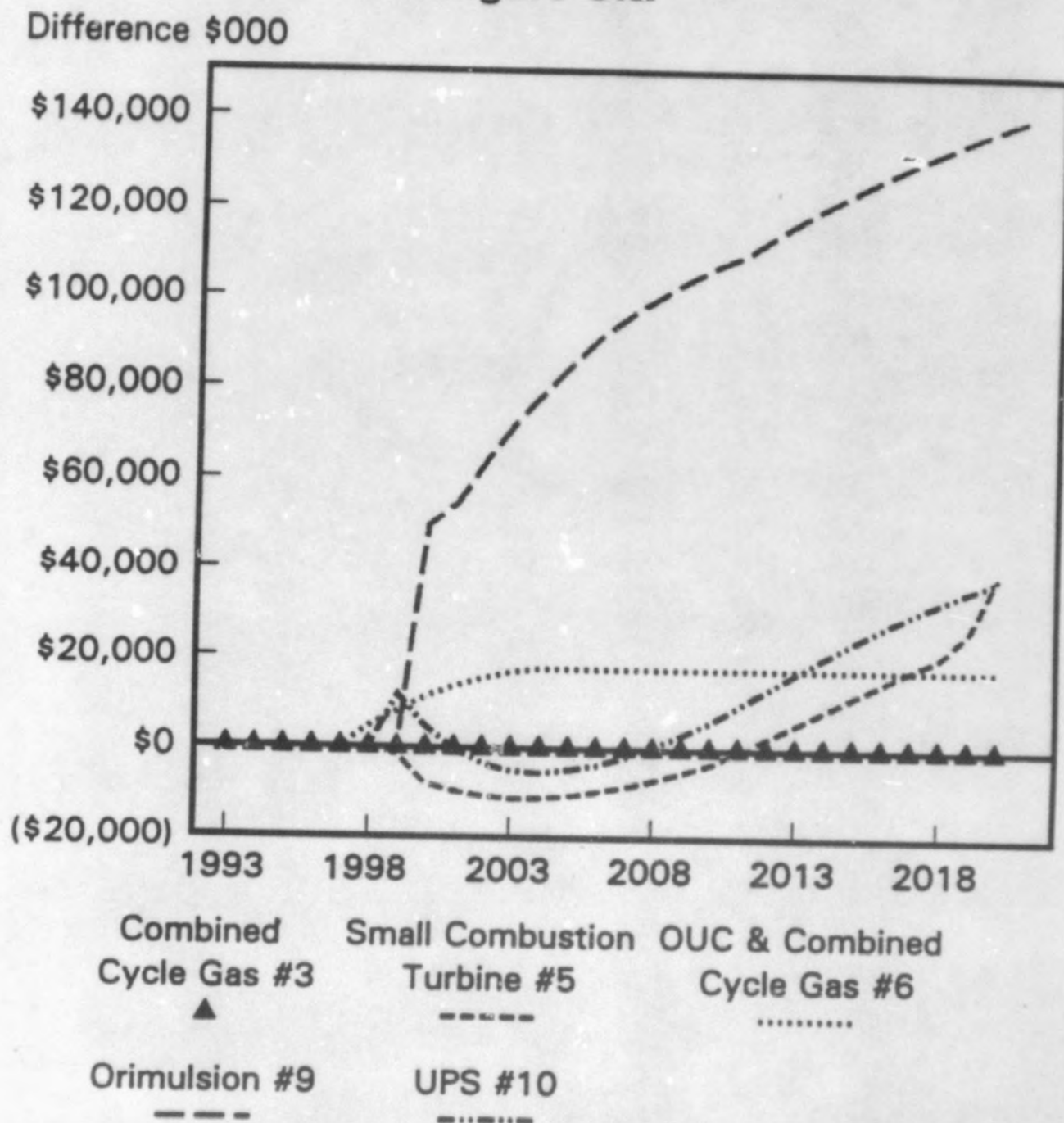
Each of the 27 scenarios in the "decision tree" shown in Figure 8.1 was modeled with a PROSCREEN simulation in order to calculate the Cumulative Present Worth Revenue Requirement (CPWRR) for that scenario. The CPWRR from each of the PROSCREEN runs was then weighted by its probability of occurrence and the expected (or average) value of the CPWRR of each alternative was compared to the others. The plots of the expected value CPWRR differentials are shown in Figures 8.2 and 8.3. These figures display the average economic cost of the scenarios relative to each other. The interpretation of these figures is explained in detail in the Economic Analysis Subsection below.

The second part of the decision analysis is the evaluation of the alternatives under the individual 27 scenarios. For the purpose of this part of the analysis, the CPWRR is *not* multiplied by its probability of occurrence. Instead, all 27 scenarios are compared to a base set of 27 scenarios. (In this case Alternative 3 is the base scenario.) The 27 differences are then sorted from lowest cost (or highest savings) to highest cost (or lowest savings). The scenario probability is assigned to the scenario, but it is *not used as a weighting factor*. Instead, the probabilities are accumulated from lowest to highest cost. The interpretation of these figures is explained in the Risk Analysis subsection below.

Comparison of Alternatives

Cumulative Present Worth Revenue Requirements

Figure 8.2

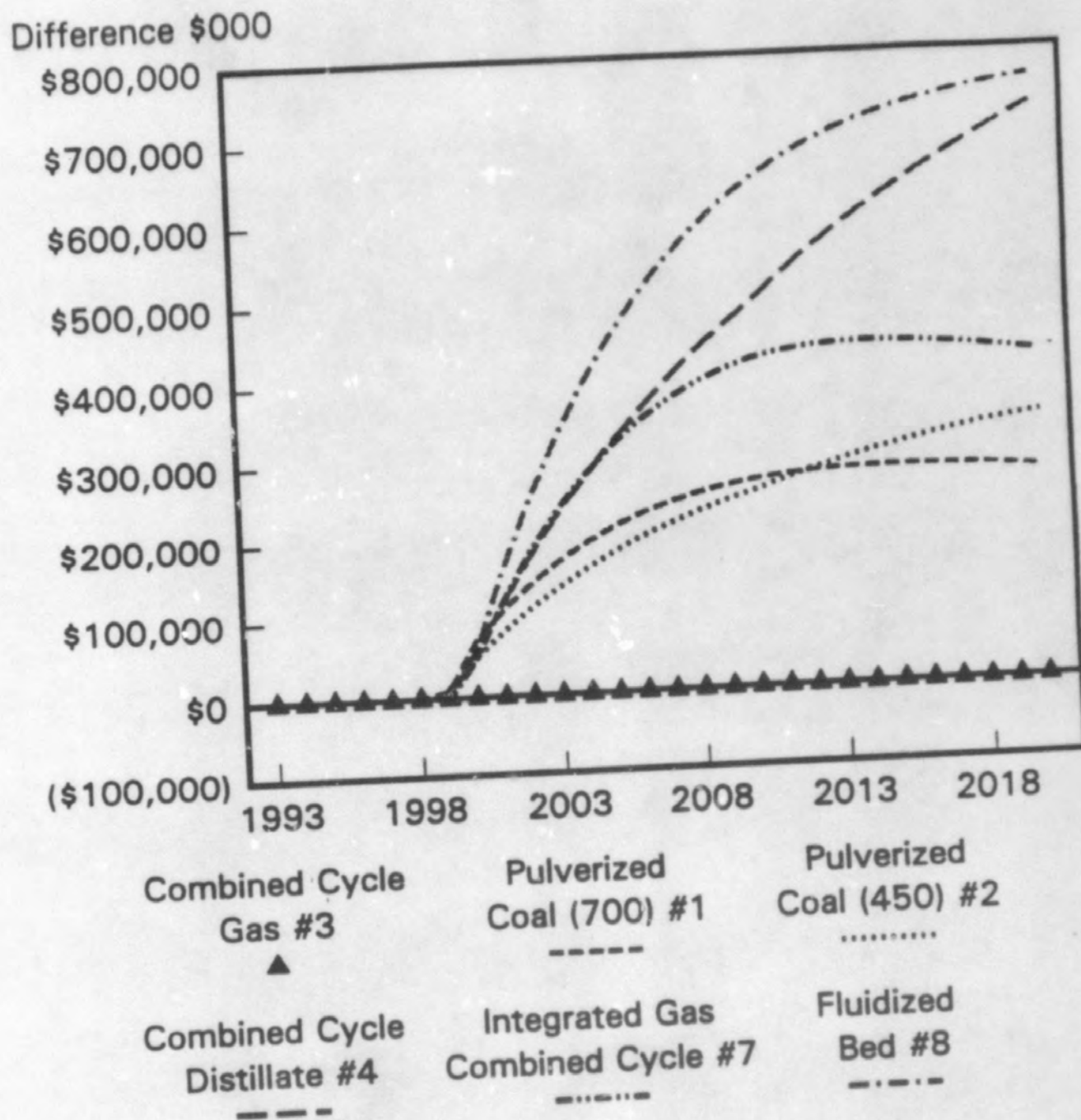


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Comparison of Alternatives

Cumulative Present Worth Revenue Requirements

Figure 8.3



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ECONOMIC AND RISK ANALYSIS

ASSUMPTIONS FOR PROSCREEN ANALYSIS

The financial and economic parameters used by PROSCREEN in the economic analysis for the competing alternatives were developed by the Business Planning Department. The projected capitalization ratios are based on the long-term capitalization objectives of Florida Power. The capital cost components and inflation rate assumptions are the expected long-term average levels for these costs and rates. The federal and state income tax rates are the currently effective statutory rates. A summary of these assumptions is shown in Table 8.2.

ECONOMIC ANALYSIS

One of the primary objectives of selecting an expansion alternative is to select the one with the lowest long-term costs. Figures 8.2 and 8.3 show the differential between expected value of the CPWRR of each alternative versus the expected value of the CPWRR of Alternative 3. The Study runs through the year 2020. These figures show that there is no alternative that has a lower CPWRR than Alternative 3. Two alternatives, 5 and 10, are less expensive for a number of years, but become more expensive in the long term.

It is important to note that the vertical axis on Figures 8.2 and 8.3 is the difference in thousands of dollars of present value required revenue. Figure 8.2 includes the most competitive alternatives. The vertical scale reaches \$145 million in this figure. Figure 8.3 has less competitive alternatives, and the vertical scale reaches \$800 million.

As seen on these figures, the primary result of the economic analysis is the fact that Alternative 3 has the lowest 30-year expected CPWRR. The addition of gas-fired combined cycle units is the best combination of capital cost and fuel costs, resulting in the lowest revenue requirement.

ECONOMIC AND RISK ANALYSIS

Summary of PROSCREEN Economic Assumptions
Table 8.2

After Tax Discount Rate		9.46%
Incremental AFUDC Rate		9.46%
Projected Capitalization Ratios	Debt	45%
	Preferred	8%
	Equity	47%
Projected Cost of Capital	Debt	9.5%
	Preferred	8.5%
	Equity	13.0%
Tax Rates	State:	5.5%
	Federal:	34%
	Effective:	37.63%
Book Life	Fossil Units:	30 years
	Combustion Turbines:	20 years
	Combined Cycle:	30 years
	IGCC:	30 years
Tax Life	Fossil Units:	15 years
	Combustion Turbines:	15 years
	Combined Cycle:	15 years
	IGCC:	15 years
Annual Escalation Assumptions (1991-2020)	General Inflation:	5.1%
	Plant Construction Cost:	5.1%
	O&M Cost:	5.1%

ECONOMIC AND RISK ANALYSIS

FORECAST SENSITIVITY

An alternative expansion plan may have a low expected CPWRR, but it may not be a good long-run choice for a utility or its customers. This is true if the alternative is highly sensitive to input assumptions that have large or rapidly changing levels of uncertainty.

To test for such sensitivities, each alternative is compared to a base alternative under 27 different scenarios. The 27 individual comparisons are sorted in descending order of highest savings to highest cost, and the probabilities of the scenarios are accumulated. The resulting data is then plotted to produce a risk analysis plot.

The risk analysis plots for the 10 alternatives in this study are shown in Figures 8.4 and 8.5. The vertical axis shows the cost difference between an alternative and the base alternative. A negative number means that the given alternative is less expensive, and a positive number means that it is more expensive. The horizontal axis is the cumulative probability going from lowest to highest cost. The crossover point shows what the probability of a lower cost would be.

As an example, Figure 8.4 shows that Alternative 10 has a 40% probability of being less expensive than Alternative 3. Alternative 10 has a 60% probability of being more expensive. This graph also shows that Alternative 10 could be approximately \$225 million less expensive than Alternative 3, or it could be approximately \$290 million more expensive. These figures provide a way to measure the "riskiness" of an alternative when its long-term expected value looks competitive with another alternative. This technique can also be used to discover what input assumption produces the highest risk by identifying the scenarios that resulted in the highest cost differentials.

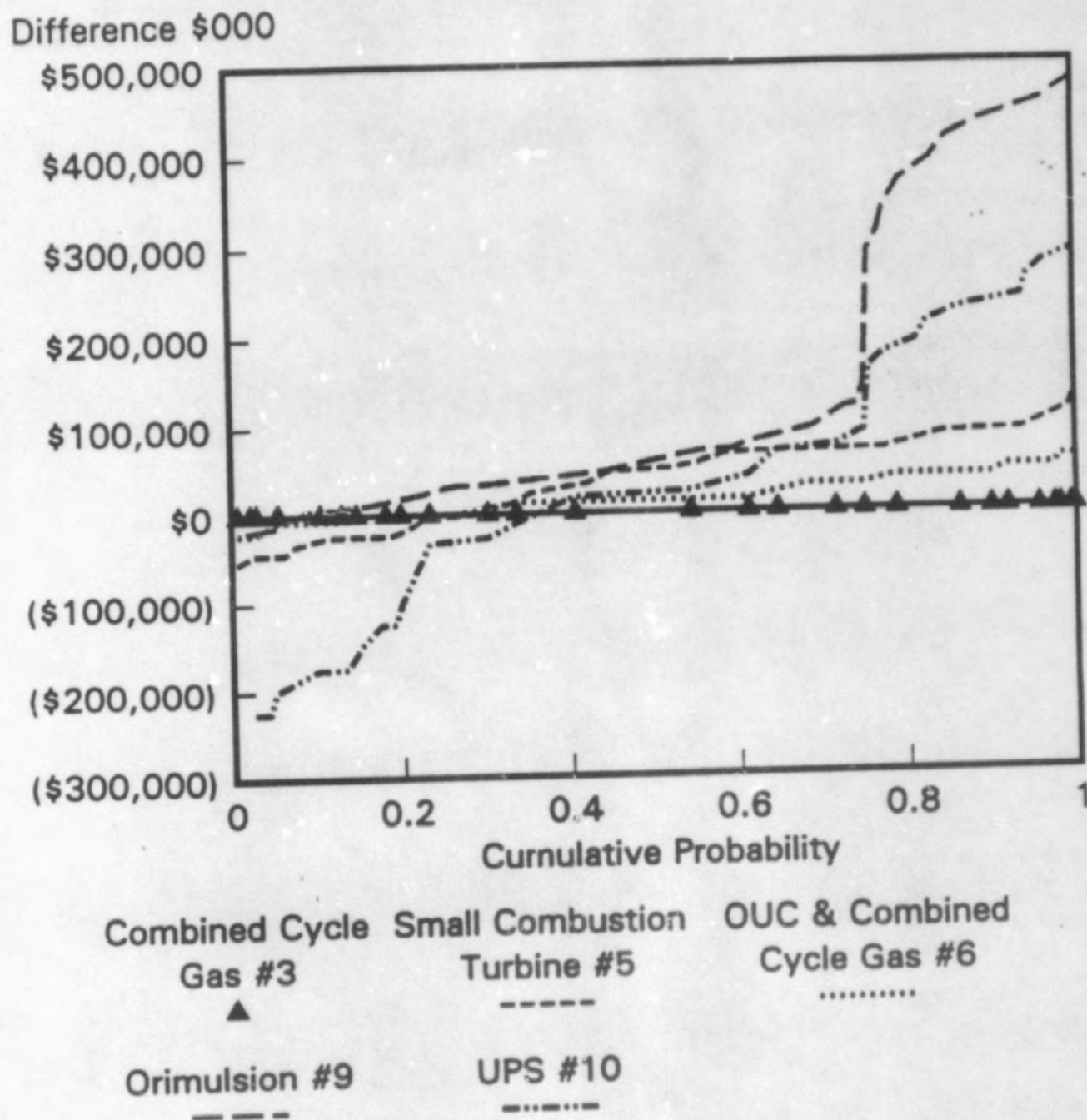
OTHER RISK FACTORS

Other factors are also considered as part of the risk analysis. An alternative is considered to be less risky if there is more flexibility in the fuel supply. For example, combined cycle units can burn natural gas or distillate fuel. They are also capable of being converted to burn

Risk Analysis in Year 2020

Cumulative Present Worth Revenue Comparison

Figure 8.4

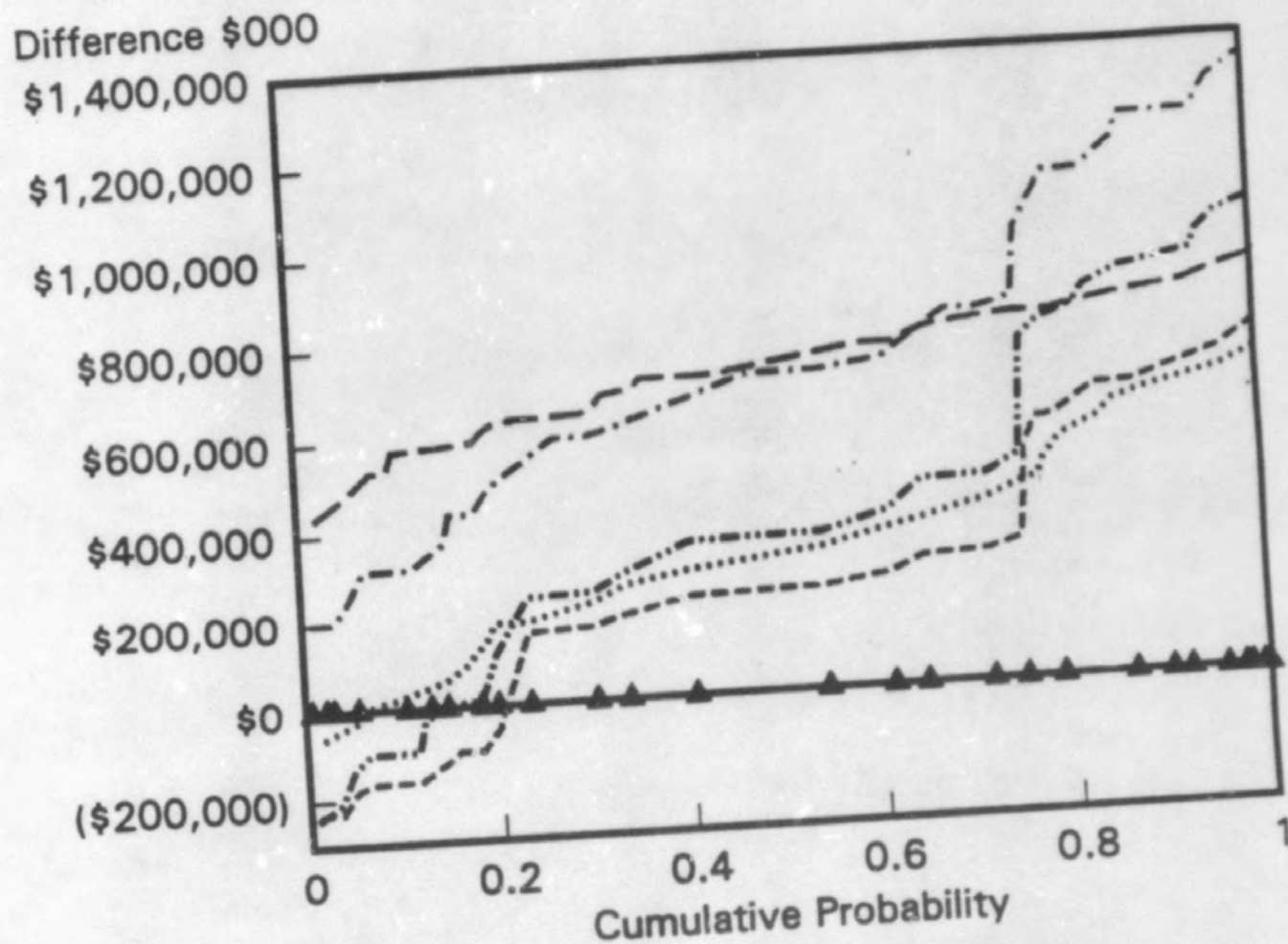


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Risk Analysis in Year 2020

Cumulative Present Worth Revenue Comparison

Figure 8.5



Combined Cycle
Gas #3
▲

Pulverized
Coal (700) #1

Pulverized
Coal (450) #2
.....

Combined Cycle
Distillate #4

Integrated Gas
Combined Cycle #7

Fluidized
Bed #8

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synthetic gas produced by a gasification process using coal as a feedstock. This makes the combined cycle units more flexible than a pulverized coal plant that is limited to coal as a primary fuel.

The requirements of the Clean Air Act make it essential to have a plan that not only meets the expected number of allowances, but has the operational flexibility to meet unexpected circumstances such as longer than expected unit outages. An extended outage of a major base load plant may require that other units will have to be run off of economic dispatch in order to comply to the FPC emissions limit. The combined cycle units in Alternative 3 can be run at high capacity factors in order to reduce the total system emissions.

CONCLUSION

This section has described the economic and risk analysis of the 10 Alternative Plans developed in Section 7. The analysis employs a decision analysis framework to find not only the alternative with the lowest expected present worth revenue requirement, but also an alternative without inordinate exposure to changes in its future cost effectiveness. The results of these analyses, along with a summary of additional information concerning each alternative, are displayed in Appendix E.

From this analysis, Alternative 3 emerges as the most cost-effective and lowest risk expansion alternative for the customers of Florida Power Corporation. This alternative is expected to save a minimum of approximately \$17 million relative to the next best alternative. Furthermore, Alternative 3 does not present any large risks with respect to cost effectiveness. The technical and economic characteristics of Alternative 3 - in particular, its modularity and flexibility — make it the best expansion plan in the increasingly complex utility construction and operating environment.

ECONOMIC AND RISK ANALYSIS

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Section 9:

FINANCIAL ANALYSIS

INTRODUCTION

FPC's planning for major capital expenditures such as the Polk County units includes an assessment of the overall financial viability of the currently proposed construction program over an appropriate time frame, which in this study was a nine-year planning horizon (1992-2000). The purpose of this financial viability assessment is to verify that the overall construction program, including the proposed Polk County units, can be financed by Florida Power while minimizing adverse financial impacts. This section describes the financial analysis conducted by FPC. The results of this analysis show that FPC can fund its construction program, including the Polk county units, and maintain its financial integrity.

FPC's analysis also included an evaluation of the financial impact of planned power purchases. While purchased power can be beneficial when used prudently, reliance on external sources of generating capacity has financial impacts similar to those associated with debt and other fixed obligations of Florida Power. In recognition of this fact, the major bond rating agencies include the financial impact of purchased power in the determination of financial stability and creditworthiness of investor-owned electric utilities.

FPC has concluded that the amount of power purchases has become a large enough factor in FPC's mix of resources and overall financial posture to have a material effect on FPC's credit rating. It would be financially imprudent for FPC to make more power purchases than are currently planned. Concomitant with the conclusion that it would be unwise to increase power purchases, FPC's analysis also shows that its long-term financial interests are best served if Florida Power owns, and rate bases, a substantial portion of its future generation needs.

FINANCIAL ANALYSIS

METHODOLOGY

The evaluation of the overall financial viability of the capacity expansion plan began with the preparation of a supporting financial plan covering the period 1992-2000. The financial plan outlines the timing and type of financial steps Florida Power will need to undertake to finance total construction requirements, including the Polk County units. The capital cost associated with gas pipeline construction was not included in this financial plan because the extent of FPC's ownership of these facilities is not certain at this time.

As explained more fully in Section 10, the three options being investigated to deliver natural gas to the Polk county site are: 1) having another entity build a pipeline based, in part, on FPC's commitment to transport gas; 2) obtaining gas transportation from Florida Gas Transmission; and 3) building and owning a pipeline with the participation of other equity partners. FPC will analyze the financial effect of the build-and-own option as its parameters become more clear. The financial conclusions discussed in this section are consistent with either of the third-party gas delivery options.

Four areas of results from FPC's financial plan were analyzed to evaluate financial viability. First, key financial ratios were evaluated against internal FPC objectives and against well recognized financial tests applied by credit rating agencies. Second, the viability of the aggregate amount and timing of necessary new debt and equity issues was verified. Third, the plan was reviewed from the broad perspective of investors who would assess Florida Power, giving primary emphasis to a demonstration of sustainable financial stability and a healthy, stable rate of growth. Fourth, the impact on customer rates resulting from projected activities was measured on both a nominal and real (inflation-adjusted) basis.

Florida Power Corporation currently enjoys a solid financial reputation, as evidenced by the "AA" class credit quality rating FPC has received from the major credit rating agencies, including Duff & Phelps, Fitch Investors Services, Inc., Moody's Investors Service, and Standard & Poor's. One of FPC's primary goals is to maintain its "AA" credit rating.

FPC's financial plan provides the means to fund construction expenditures as they occur, as well as to permanently finance the long-term growth of Florida Power. This plan relies first

FINANCIAL ANALYSIS

on short-term debt, which is periodically replaced with permanent debt issues, common stock, and/or preferred stock offerings. For purposes of financial planning, it is assumed that bonds are issued only when short-term credit limits are approached and permanent financing is required.

The resulting financial trends and associated financing plan were reviewed for consistency as an integral whole, just as they would be viewed by the financial community. Essential features of the financial plan include a smooth growth rate, regular presence in financial markets, a regulatory strategy that balances rate levels with capital needs and growth, and manageable risks. In addition, individual capital projects, such as the Polk County units, have been reviewed relative to potential concerns such as project duration, technology and regulatory risk, and rate shock.

FINANCIAL ANALYSIS OF THE CONSTRUCTION PROGRAM: RESULTS

FPC's financial analysis concluded that the Polk County units can be financed and constructed with FPC maintaining adequate financial integrity. The robust growth foreseen for FPC is supported by a reasonable, manageable financing plan designed to supplement internally generated funds. The analysis shows the cost of electricity increasing at a rate approximately equal to the rate of inflation, resulting in a price that is essentially constant in real terms over 1992-2000.

FPC's review of the financial parameters resulting from the capacity expansion plan is based on its corporate financial model. This model includes a representation of FPC operations as well as the accounting and regulatory environment unique to FPC. The model is capable of creating a detailed *pro forma* financial projection subject to a given set of assumptions. Key assumptions used in the plan include generation and transmission construction escalation rates, which are based on forecast data provided by Data Resources, Inc. The financial return on equity is based on maintaining the regulatory return on equity within the allowed range relative to a floor of 12.6%. The remaining inflation and financial assumptions were developed internally and are the current basis for financial planning and evaluation. A summary of these assumptions is shown in Table 9.1.

Financial and Economic Assumptions Used for Business Planning Financial Analysis

Table 9.1

	1992	1993	1994	1995	1996	1997	1998	1999	2000
Inflation Assumptions:									
Generation Escalation	4.0%	5.4%	5.2%	5.5%	5.6%	5.6%	5.5%	5.8%	5.9%
Transmission Escalation	2.4%	4.2%	4.5%	5.2%	5.7%	5.6%	5.6%	5.8%	5.7%
General Inflation	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%	4.5%
Financial Assumptions:									
First Mortgage Bonds	9.7%	9.7%	9.7%	9.7%	9.7%	9.7%	9.7%	9.7%	9.7%
Preferred Stock	9.2%	9.2%	9.2%	9.2%	9.2%	9.2%	9.2%	9.2%	9.2%
Common Equity	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%	13.0%
Bank Loans	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Short Term Investments	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%	8.0%
Tax Rate Assumptions:									
Federal Income Tax Rate	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%	34.0%
State Income Tax Rate	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Effective Tax Rate	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%	37.6%

Source: Data Resources, Inc.
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Within the model, each functional area of operating and maintenance expenses is assumed to grow at a rate based on customer growth and/or inflation, with adjustments for specific scope changes based on new events or activities. Due in part to several new activities dictated by environmental and regulatory requirements, total O&M expenses are expected to increase at a rate slightly above inflation during 1992-2000. Purchased power capacity charges associated with the Southern Company and Qualifying Facilities are projected to increase from \$34 million in 1992 to \$278 million in 2000.

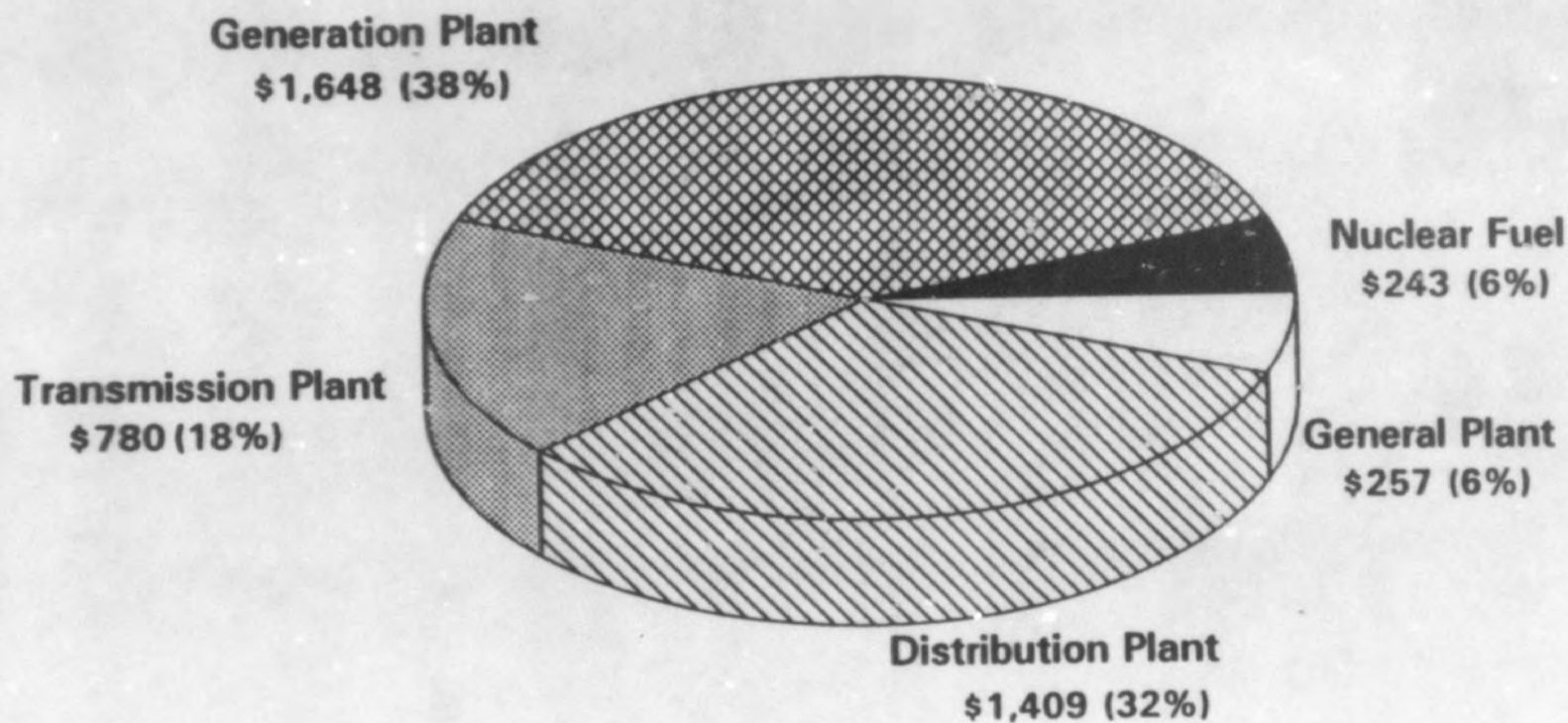
Capital expenditures are projected to total \$4.3 billion (excluding AFUDC) for 1992-2000, including \$1.6 billion in total generation construction. In the near term, 768 MW of new combustion turbine capacity will be placed in service during 1992-1993 at a cost of \$226 million. During 1998-2000, another 940 MW of combined cycle capacity will be added in increments at a total cost of \$802 million. The 500 kV transmission interconnect with the Southern Company is now projected to be in service in 1997 at a cost of approximately \$314 million. The remaining capital program consists of smaller projects and expenditures to accommodate customer growth (see Figure 9.1).

Of the total 1992-2000 capital requirements of \$4.3 billion, \$2.9 billion (67% of the total) is expected to be provided by internally generated funds. The remaining \$1.4 billion is expected to be provided by approximately \$576 million in common stock issues (13% of the total) and \$858 million in debt issues (20% of the total). Total capitalization is projected to grow at an average rate of 6.2% during 1992-2000 to a total of \$4.8 billion in 2000. The equity capitalization ratio rises into the range of 49.5% to 52.2% during 1995-2000.

Reliance on advanced combined cycle units for new capacity provides financial flexibility in a number of respects. The Polk County units can be added in 235 MW increments, can operate as base or intermediate units, and have relatively short construction lead times, which allows ample time to react to changes in projected load growth. Overall, the construction program is expected to be perceived as being low risk. Construction expenditures display a stable upward trend, with peak annual expenditures of \$611 million in 1999 projected to be 30% above the average annual expenditure level for the decade.

1992 - 2000 Total Construction Expenditures (Million \$)

Figure 9.1



FINANCIAL ANALYSIS

In summary, the financial plan demonstrates that Florida Power is capable of maintaining adequate financial integrity given the plan's assumptions, including appropriate and timely regulatory treatment. The ratio of net external financing to total capitalization is projected to remain below 6% on an annual basis for most of the next decade. This is substantially below the 10-16% levels reached during FPC's last major construction cycle, which included construction of the Crystal River 4 and 5 pulverized coal units.

IMPACT OF PURCHASED POWER ON CREDITWORTHINESS

The purchased power contracts that impact credit risk are primarily long-term contracts that require the buyer (such as FPC) to make capacity payments on a take-or-pay or take-and-pay basis. These payments represent a firm obligation to make predetermined payments that are not dependent on the amount of energy purchased. Contracts that require payment only when capacity is available (take-and-pay) affect credit ratings to a slightly lesser degree than unconditional (take-or-pay) contracts. It is recognized that a seller's ability to finance capacity is based solely on its contract with the purchasing utility.

IDENTIFICATION OF POSSIBLE RISKS

Purchased power carries financial as well as operational risks. The financial risks are:

- **Off-balance Sheet Liability.** While financial accounting standards do not necessarily require power contracts to be reported as a balance sheet liability, rating agencies regard these obligations as long-term liabilities not unlike long-term debt. Balance sheets are routinely restated by rating agencies to reflect the additional liability as debt equivalents when financial ratios for Florida Power are computed.
- **Income Statement Risk.** Capacity payments are fixed charges in connection with payment for the use of a capital asset. They are tantamount to payment of interest expense incurred. Interest coverages are adjusted by rating agencies to appropriately

FINANCIAL ANALYSIS

reflect the capacity payment obligation in order that credit ratios for companies building and companies buying capacity are comparable.

- **Rate Base Liquidation.** Purchased power is generally recovered dollar for dollar, either through base rates or the fuel adjustment. Rate base growth is reduced and can actually become negative when depreciation of existing assets is not counterbalanced by the addition of new generation. Earnings and cash flow growth are also slowed or eliminated. This reduction in internal funds generation can severely reduce a company's ability to finance the construction of future facilities when required to meet customer demands. The depreciation cost recovery built into capacity payments goes outside the regulated utility for the benefit of the owners of the purchased capacity.
- Purchased power cannot prudently be relied on as a long-term vehicle for the acquisition of generation assets. Because Florida Power is required to serve its load at all times, it must be able to step in at any time to replace purchased power contracts that expire or projects that falter. FPC must provide the lowest cost capacity to serve its customer base.

Operating risks associated with purchased power fall into the following categories:

- Reduced generation dispatching flexibility, and
- Reduced maintenance outage scheduling flexibility

These risks are discussed in Section 11 in additional detail.

ASSESSMENT OF THE EXTENT OF RELIANCE ON PURCHASED POWER

Appropriate amounts of purchased power can be beneficial to a utility and its customers. Purchases can at times provide low cost sources of power and provide a diversity of capacity. The point at which additional risks from reliance on purchased power outweigh the benefits is not defined precisely nor is it the same for every utility.

FINANCIAL ANALYSIS

The ultimate credit rating assigned to any company will depend on many qualitative factors as well as quantitative analysis. The nature of the power contracts, their overall fit with the utility, and the reliability of suppliers must all be considered before a determination can be made as to how much purchases impact ratings and how much purchased power can be tolerated with acceptable risk.

In the generation expansion plan developed in this study, purchases reach a maximum of 15% of total resources to meet peak demand in 1998. Total purchased demand charges reach a maximum of 179% of total interest charges in 1997. This level of purchases is considered quite high relative to the utility industry as a whole. The projected level of purchases is not excessive or imprudent for FPC given the overall circumstances inherent in the plan. However, significant additional purchases would not be consistent with maintenance of a desirable level of financial integrity and would result in higher costs to FPC's customers.

FINANCIAL ANALYSIS

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Section 10: NATURAL GAS SUPPLY AND TRANSPORTATION

INTRODUCTION

This section discusses the status of FPC's efforts to secure adequate and reasonably priced natural gas supply and transportation to fuel the Polk County units beginning in 1998. The first step in the fuel supply analysis was an assessment of the long-term natural gas supply situation in the United States. This evaluation led FPC to the conclusion that natural gas will be available in sufficient quantities to fuel these units over the time frame of the evaluation and beyond. FPC has had numerous discussions with potential gas suppliers, but FPC has not yet entered into a contract to purchase a firm supply. Florida Power believes that it would be inappropriate to enter into a long term contract at this juncture. However, FPC is firmly convinced that the supply of natural gas will be sufficient to meet its needs.

FPC has also carefully evaluated the options to reliably transport sufficient quantities of natural gas to the site. These options for construction of pipeline capacity are currently under active study. Because new major pipeline construction tends to be driven by customer demand, the licensing of the Polk County units to burn natural gas will be the key to ensuring timely completion of a pipeline project, regardless of which pipeline option is ultimately chosen.

USE OF NATURAL GAS AT EXISTING FPC UNITS

FPC has been using natural gas as a fuel for generation since the late 1950s. FPC had firm supply and transportation contracts from 1958 to 1978 which were not renewed because the Fuel Use Act of 1978 prohibited the use of natural gas as a boiler fuel for electric generation. Since that time, FPC has maintained interruptible supply contracts with Florida Gas Transmission (FGT) and South Georgia Natural Gas (SGNG). The contract with FGT was for interruptible sales service and remained in place until August 1, 1990, at which time FGT became an "open access" pipeline. Subsequently, FPC retained the interruptible sales

NATURAL GAS SUPPLY AND TRANSPORTATION

service and added an interruptible transportation contract. Thereafter, availability of transportation from the FGT system has been minimal.

Interruptible transportation contracts have been in place with SGNG and Southern Natural Gas since 1987. Spot and short-term purchases for the Suwannee Plant resulted in significant quantities of gas being burned, up to a maximum of 30 million cubic feet per day (MMCFD). In June 1991, SGNG constructed a new natural gas line to Jacksonville that seriously constrained its ability to provide interruptible transportation service to Suwannee. Capacity has been limited to a maximum of approximately 10 MMCFD. FPC did not commit to firm supply and transportation because the units that can burn gas are not base loaded and it is difficult to predict when those units will be brought on line and how long they might run.

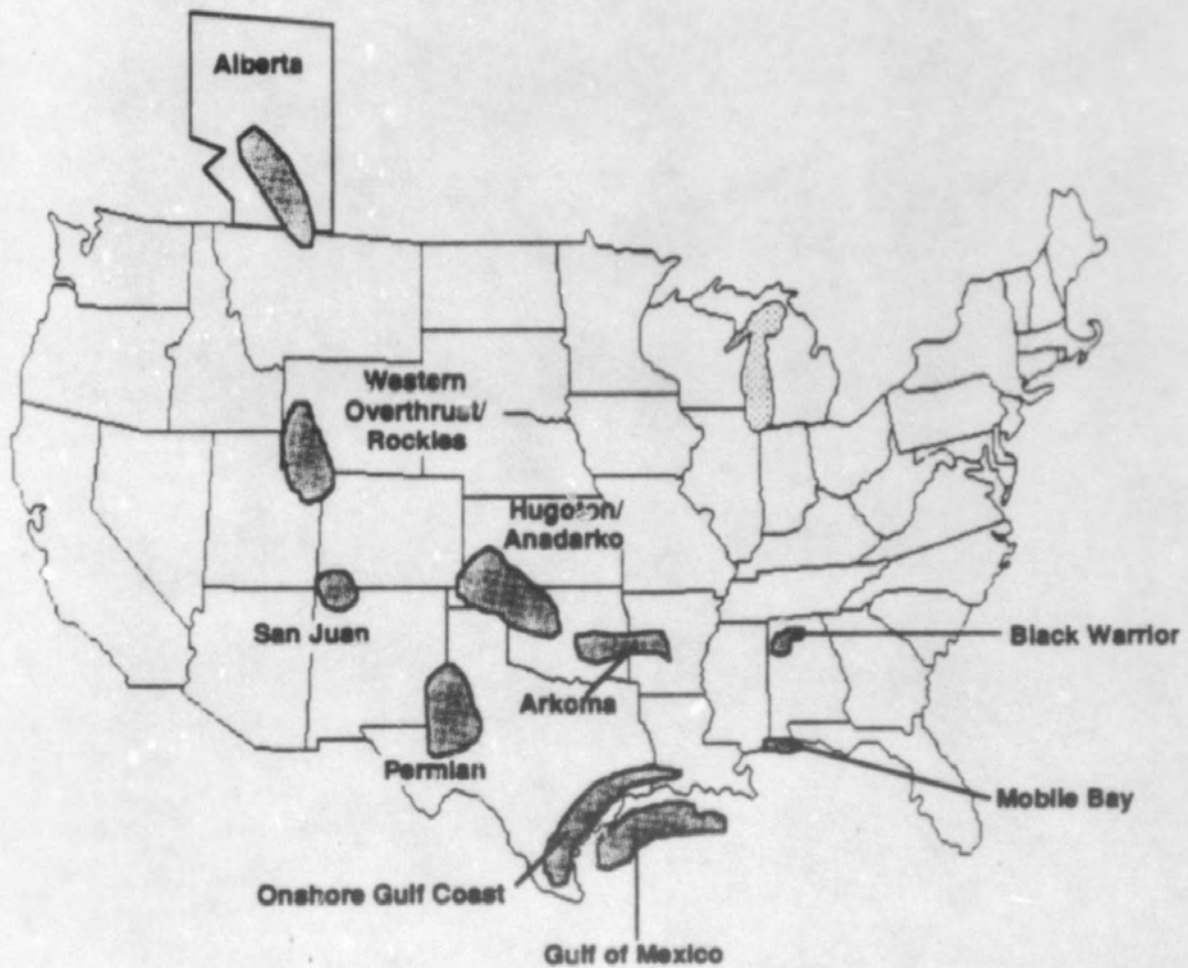
In view of these circumstances, it became readily apparent that gas supply needs for the remainder of FPC's system should be integrated with the Polk County requirements. The capability of FPC's existing units to burn gas, coupled with the substantial quantity of gas that could be consumed at FPC's Anclote plant with a possible conversion in late 1994 or early 1995, must also be considered. The conversion of Anclote would provide for a phased-in approach to the gas supply at Polk County and would increase the security of the supply for those units by flowing significant quantities of gas to the FPC system several years in advance of the currently expected in-service date of the Polk County units. For all these reasons, FPC is assessing this long-term availability of gas for several units on its system.

LONG-TERM SUPPLY OUTLOOK

Natural gas occurs in many regions of the United States. Major reserves exist both onshore and offshore along the Texas and Louisiana Gulf Coasts, along with recent important discoveries in the Mobile Bay area. The close proximity of these areas to Florida provides a wide diversity of choice in selecting supply resources. Figure 10.1 shows the general areas of the country where the greatest reserves are located. It must be remembered, however, that

Major Natural Gas Supply Areas

Figure 10.1



Source:
Arthur Andersen Worldwide Organization/Cambridge
Energy Research Associates

Integrated Resource Study

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NATURAL GAS SUPPLY AND TRANSPORTATION

as pipeline systems continue to expand and improve, it becomes increasingly possible, and indeed probable, for gas to be supplied from any of the other producing areas. In fact, gas was recently transported from Western Canada to Florida by another utility.

In order to accurately assess the long-term availability of gas supply, FPC met with numerous major suppliers and marketers and extensively analyzed published data regarding available and projected reserves. FPC has had numerous meetings with many of the major producers, including the seven largest holders of reserves: Amoco, Exxon, Mobil, Arco, Shell, and Texaco. The objectives of the meetings were to determine the security of supply for the long term and to discuss the general terms and conditions applicable to long-term supply agreements. The consensus of these meetings is that gas supplies will be available for the foreseeable future. The top 20 reserve holders account for approximately 55% of total U.S. reserves (Table 10.1), which ensures that a competitive situation will exist to supply future needs. Furthermore, when new discoveries are being developed, sufficient pipeline capacity is usually not in place to transport the full amount deliverable from the wells. Since there is more gas available than pipeline capacity to move it, the result is "gas-to-gas" competition, which helps ensure an adequate supply at reasonable cost.

In addition to meeting with the major producers, meetings were held with independent marketers and producers and with pipeline affiliated marketers, including Brooklyn Interstate Natural Gas, Citrus, Eastex, Phibro, Union Pacific, and Williams. The results of those meetings also indicated a very positive outlook for the availability of natural gas in the long term. FPC also reviewed available data in an effort to independently confirm the information provided by suppliers and marketers. The review of various reports available on the status of natural gas reserves was conducted to determine if these reports corroborated the optimistic picture provided by the producers and marketers. The following figures show that additions to reserves versus production, projected demand versus projected reserve additions, and total estimated reserves available support the information gained from the producers and marketers.

NATURAL GAS SUPPLY AND TRANSPORTATION

- **Table 10.1: Proved U.S. Natural Gas Reserves**

Shows the proved reserves held by the 20 largest gas companies who account for 55% of U.S. reserves. This figure demonstrate that, from 1988-1989, additions to reserves kept pace with demand.

- **Figure 10.2: Production vs. Reserve Additions**

Shows that reserve additions by all suppliers generally kept pace with net production from 1977 through 1989.

- **Table 10.2: Gas Supply Trends**

Shows the projected demand versus supply from 1989 through the year 2010. This projection was made by the Gas Research Institute, an organization specializing in such projections, and shows that supply and demand will remain in balance.

- **Table 10.3: Total U.S. Gas Reserves**

Shows the total gas reserves as determined by the U.S. Department of Energy as of 1988 and its calculations confirm over 1,000 TCF. The U.S. Department of Energy determination is consistent with a recently published study by Enron Corporation.⁴

A recent survey by Arthur Andersen also shows that additions to reserves in 1990 were 106% of production despite the low prices that prevailed.⁵

⁴Enron Corporation, *Outlook for Natural Gas*.

⁵ Oil and Gas Reserve Disclosures - Arthur Andersen & Co., S.C.

Proved U.S. Natural Gas Reserves Held By The 20 Largest Gas Companies

TABLE 10.1
(Billion Cubic Feet)

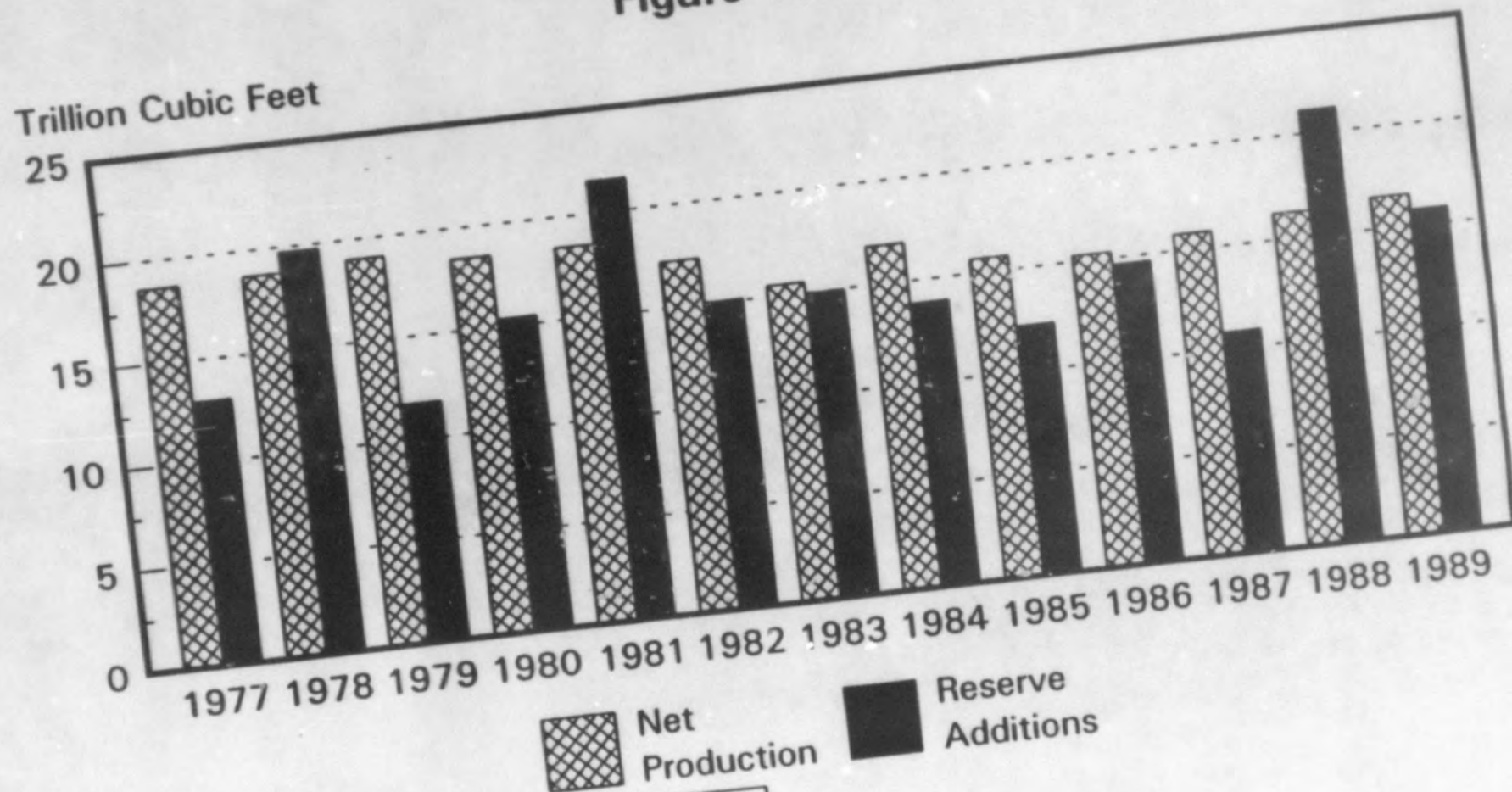
Company	1988 Year-End Reserves	1989 Year-End Reserves	1989 Reserve Replacement %
Amoco Corporation	12,371	12,254	99
Exxon Corporation	9,341	9,365	100
Chevron Corporation	8,274	7,739	94
Mobil Corporation	7,515	7,347	98
Atlantic Richfield Company	6,373	6,452	101
Royal Dutch/Shell	6,248	6,223	100
Texaco Inc.	4,655	4,834	104
Unocal Corporation	4,320	4,130	96
Burlington Resources	3,804	3,962	104
Phillips Petroleum Company	3,365	3,585	107
USX Corporation	3,048	2,792	92
Occidental Petroleum Corporation	2,568	2,489	97
Union Exploration P'ts.	2,480	2,425	98
Conoco Inc.	2,154	2,232	104
British Petroleum Company	2,273	2,171	96
Oryx Energy Company	2,242	2,146	96
Mesa Limited Partnership	2,251	2,110	94
Anadarko Petroleum Corporation	1,704	1,671	98
Union Pacific Corporation	1,518	1,580	104
Enron Corporation	1,199	1,312	109
Total	87,703	86,819	99

Source: Cambridge Energy Research Associates/Arthur Andersen Worldwide Organization

Natural Gas Production Vs. Reserve Additions

Lower 48 States

Figure 10.2



Source: DOE/EIA, U.S. Crude Oil, Natural Gas, & Natural Gas Liquids Reserves: Annual Report. Integrated Resource Study, Docket No. 910759-EI

Gas Supply Trends in the 1991 Edition
of the GRI Baseline Projection
(Quads)
Table 10.2

Production, Imports, and Other Sources	Actual	Forecast		
	1989*	1995	2000	2010
PRODUCTION				
Base Technology	16.6	14.5	14.4	12.8
Advanced Technology (+)	<u>0.0</u>	<u>1.3</u>	<u>2.7</u>	<u>5.1</u>
Lower 48 Production**	16.6	15.7	17.1	17.9
Southern***	0.2	0.2	0.2	0.3
Northern**** (+)	<u>0.0</u>	<u>0.0</u>	<u>0.0</u>	<u>1.2</u>
Alaskan Production	0.2	0.2	0.2	1.5
IMPORTS				
Pipeline Imports	1.3	1.8	2.0	1.8
LNG Imports	0.1	0.5	0.8	1.0
OTHER SOURCES				
Coal Gas	0.1	0.1	0.1	0.1
Other Gas*****	0.1	0.2	0.2	0.2
TOTAL PURCHASES*****	18.4	18.5	20.5	22.6
Lease and Plant Fuel (+)	<u>1.2</u>	<u>1.2</u>	<u>1.2</u>	<u>1.3</u>
TOTAL SUPPLY	19.6	19.7	21.7	23.9
Losses and Exports (-)	<u>0.2</u>	<u>0.5</u>	<u>0.5</u>	<u>0.6</u>
TOTAL DEMAND	19.4	19.2	21.2	23.3

NOTES:

- * Taken from the April 1990 DOE/EIA Natural Gas Monthly, published July 1990.
- ** Lower 48 Production does not include lease and fuel plant supplies.
- *** Southern Alaska natural gas supplies were estimated from projected Alaskan consumption.
- **** Northern Alaska natural gas represents supplies delivered to the lower 48 via ANGTS.
- ***** Other gas includes SNG from petroleum, propane-air, and refinery gas.
- ***** Total Purchases is the summation of production, imports, and other sources.

Source: GRI Baseline Projection Databook, 1991.

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U.S. Gas Reserves and Resources Assessed

Table 10.3

DEMOGRAPHIC AREAS	Technically Recoverable Gas, Tcf**
Lower 48 (Conventional)	159
Proved Reserves, Onshore and Offshore *	85
Inferred Reserves, Onshore*	23
Inferred Reserves, Offshore*	119
Extended Reserve Growth in Nonassociated Fields, Onshore	61
Gas Resources Associated with Oil Reserve Growth	219
Undiscovered Onshore Resource	134
Undiscovered Offshore Resources	800
Subtotal	
Lower 48 (Unconventional)	180
Gas in Low-Permeability Reservoirs	48
Coalbed Methane	31
Shale Gas	259
Subtotal	
Alaska	33
Reserves	3
Inferred Reserves (Cook Inlet Area)	93
Undiscovered, Onshore and Offshore	129
Subtotal	
TOTAL	1,188

NOTES:

* As of December 31, 1986.

** Volumes of gas judged recoverable with existing technology.

*** Outer Continental Shelf

Source: U.S. Department of Energy, An Assessment of the Natural Gas Resource Base of the United States, 1988.

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SUPPLY OPTIONS

When considering the options available for natural gas supplies, it is important to note that Florida is one of the largest remaining incremental growth markets for the natural gas industry. Major producers and marketers are anxious to participate in that growth, and competition will be vigorous as new pipeline capacity develops.

In addition, it is estimated that one-third of the new generation coming on line in the United States in the next 10 years will be fueled by natural gas.⁶ This is also a very large, incremental market. Adding to the interest in new markets is the fact that, although the number of residential gas customers is increasing, residential consumption is decreasing.⁷ This is caused primarily by more efficient appliances, improved insulation, and lowered thermostat settings during winter heating seasons.

A variety of supply options are available to FPC in structuring a supply portfolio including:

- **Long-Term Contracts.** Contracts of 3 to 5 years and longer generally fall in this category and are readily available in the market today. Major producers and some marketers are willing to sign commitments up to 15 years and in some cases even longer. Different pricing mechanisms with escalation indexed in various ways are offered along with warranted delivery clauses. In short, many suppliers will customize contracts to meet individual customer requirements. Suppliers are anxious and willing to convert a significant portion of gas that moves in the spot market to longer-term contract gas.
- **Short-Term Contracts.** Short-term contracts of 3 to 5 years and less including "spot" purchases, are readily available and can be used to balance long-term contracts and to provide flexibility to meet changing needs and market conditions. Pricing is generally done on a monthly basis but can be done for longer periods.

⁶ *Annual Outlook for U.S. Electric Power, 1991*, Energy Information Administration.

⁷ *Natural Gas Trends*, Arthur Andersen/Cambridge Energy Research Association, 1991 Edition.

NATURAL GAS SUPPLY AND TRANSPORTATION

- **Reserve Purchases.** It is possible to purchase reserves of natural gas in the ground that may be producing or nonproducing wells. This requires large, upfront capital investment and continuous operating and maintenance expenses.

SUPPLY STRATEGY

FPC's fuel procurement strategy is to structure a portfolio of supplies that diversifies the contract terms and conditions, geographical areas, and types of suppliers. The contract provisions should provide a mix of pricing mechanisms, escalation indices, volume flexibility, total amount of gas contracted for and expiration dates.

Geographical areas should be diversified enough to access different resource bases and should afford optimum flexibility in pipeline capacity utilization and routing to preferred receiving points. A diversity of supply areas will result in the ability to benefit from market changes that occur on a regional basis.

Commitments should be diversified among major producers, smaller independent producers, marketers (pipeline affiliated and independent), and others as conditions dictate.

This strategy will achieve a high degree of security of supply and will help ensure a low cost supply of gas while minimizing the short-term affects of price volatility in the market. While long-term and short-term gas supply contracts are available today from multiple sources to meet FPC's need in 1998 for the Polk units, it would be imprudent to enter into a contract for those supplies at this time. While FPC has a desire to add more gas to its system, the mix in its portfolio and the amount contracted for will depend on whether the Polk units are certified. Had FPC already contracted for gas supply to fuel these as yet unlicensed units, without receiving at least a determination of need, FPC would have been at undue and unnecessary risk for having made contractual commitments with no sure economical way of using that gas. Based on the research done to date, FPC is confident that it will be able to assemble a strong portfolio of gas supply contracts to meet its generation needs once the Polk units have received the appropriate regulatory approvals.

NATURAL GAS SUPPLY AND TRANSPORTATION

NATURAL GAS TRANSPORTATION

Existing Capability

There is one major pipeline presently serving Peninsular Florida: Florida Gas Transmission (see Figure 10.3). This pipeline has recently been expanded in two phases, with the second phase expected to be completed in late 1991 or early 1992. This will bring the approximate delivery capability to 925 MMCFD. Virtually all of this capacity has been reserved through firm service commitments.

FPC, through Gainesville Gas Company has reserved a small amount of capacity (8.8 MMCFD) as part of FGT's Phase II expansion. This natural gas transportation will be utilized by FPC's plant planned at the University of Florida.

FPC's Bartow, Higgins, Turner, and Avon Park Plant sites all have natural gas capability and are served by Florida Gas Transmission on an interruptible basis. Because of the low load factor operation of these units and the relatively low cost of residual fuel oil at these plants, there are no firm capacity commitments on the FGT pipeline for these plants. FPC's Suwannee Plant is connected to the South Georgia Natural Gas System and is also supplied on an interruptible basis.

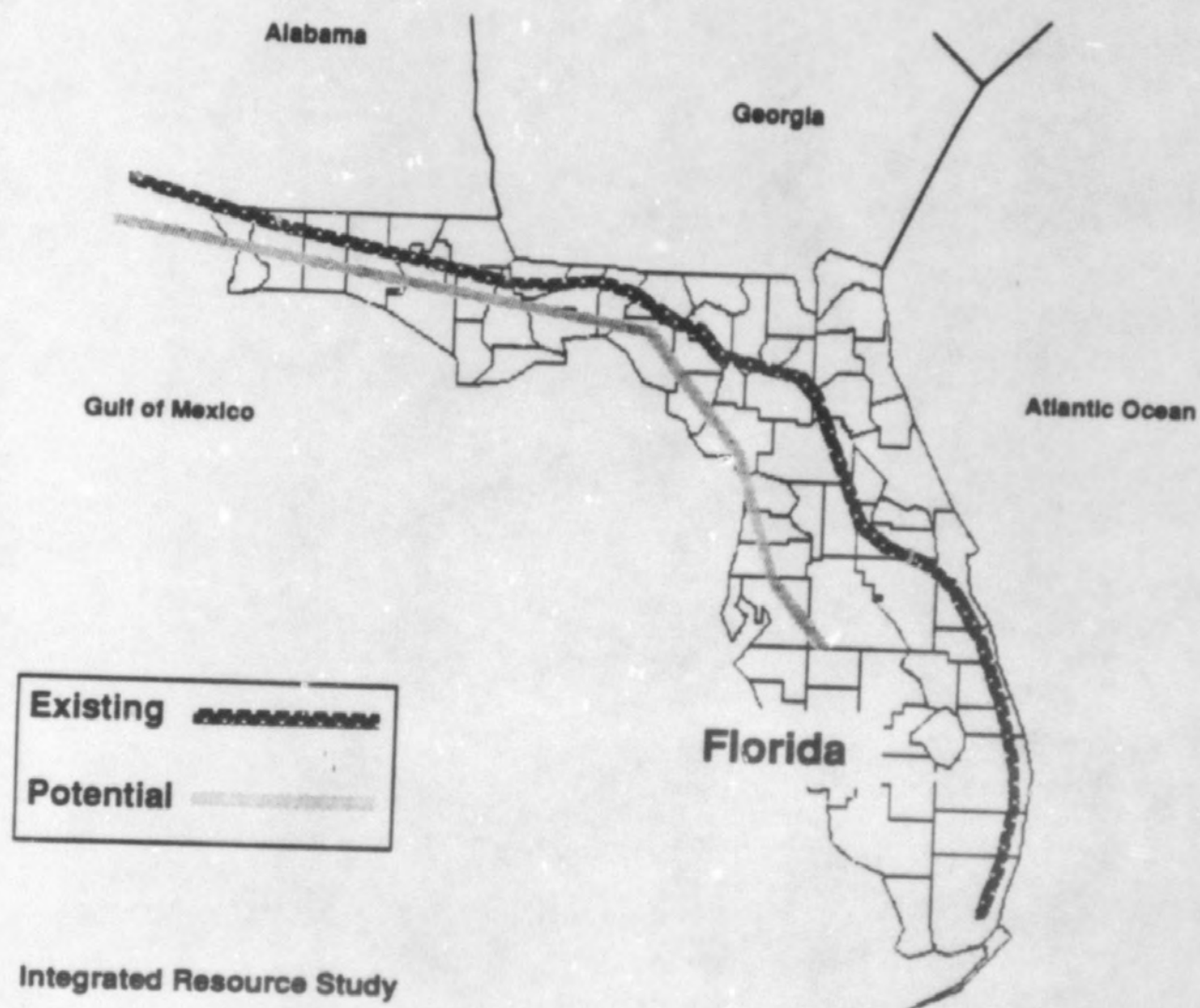
Future Capacity

FGT is currently planning a Phase III expansion of its pipeline system for the 1994/1995 time frame. The total amount of capacity requested by all potential customers in Phase III is about 6.7 BCFD. It is anticipated that only a small part of this demand will be met by this expansion. This demonstrates a very large potential market for new pipeline capacity. FPC has requested capacity on this proposed expansion in the following amounts:

- May-Sept. — 140 MMCFD
- Oct.-Apr. — 55 MMCFD

Existing and Potential Natural Gas Pipeline Capability

Figure 10.3



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The majority of this capacity would be utilized at the Anclote Plant, which would require conversion of the plant to dual fuel capability in order to burn both residual fuel oil and natural gas. This is approximately the same average amount of pipeline capacity that will be required for the Polk County units. It is expected that a firm commitment for the Anclote capacity will have to be made in late 1991.

Options for Pipeline Capacity to the Polk County Site

The Polk County units are expected to require approximately 100 MMCFD on average, with a peak demand of about 200 MMCFD for the 940 MW of capacity. FPC is considering three options to ensure there is sufficient pipeline capacity in place to meet its system needs. These options are:

- **Option A.** Develop a new independent pipeline owned by FPC and others to serve FPC's system requirements. The other owners could be pipeline companies and/or other end users of natural gas, including other utilities. This pipeline would interconnect with one or more lines, probably at the Florida-Alabama border, to access producing areas where natural gas supply could be easily secured. Figure 10.3 shows a simple one-line schematic of a new system in the State. This option would also provide access to new sources of supply and new receiving points not presently accessible.
- **Option B.** Secure capacity for Anclote Plant through FGT's Phase III expansion and for the Polk County site through a future FGT expansion (Phase IV). This option would require a continuing phased in expansion of the existing interstate pipeline capabilities into the state. FGT has indicated that such a Phase IV expansion is feasible. However, if for some reason, additional capacity beyond Phase III could not be made available in the late 1990s, lateral upgrades within the state would be utilized to transfer the Anclote supply to the Polk County units.
- **Option C.** Commit to capacity on a new pipeline to be built into the state of Florida by another pipeline company directly from the producing areas. There are several other pipeline companies in the southeast United States with an interest in providing capacity to Florida. This option would provide new gas transportation competition in the state.

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It would also potentially provide access to supply sources not directly accessible via the FGT system.

FPC continues to evaluate the potential benefits and costs of each option. For example, Option A would bring a competing pipeline into Peninsular Florida. Option A would also give FPC the potential to have significant control through partial ownership of the transportation capacity. Option B allows for a continued phased expansion approach to meeting FPC's system needs (Anclote in Phase III, Polk in Phase IV). Option C, like Option A, injects healthy competition both in capacity and supply.

Options A and C require larger long-term volume commitment to justify the construction of a new competing pipeline within Florida. Florida Power's requirements (dual fuel at Anclote plus Polk County) represent a major portion of the volume needed to justify a new pipeline.

Any of the options, all of which are under active investigation, would result in the level of service required for the Polk County units. However, it is important to receive approval as early as possible so that FPC can make the large scale commitments necessary for any of the options to be built. The ability to secure commitments from other large natural gas users would be seriously limited until FPC, as the anchor user, showed evidence of its commitment. Finally, obtaining low cost gas supplies, which is a necessary part of any plan to increase gas transportation capacity, would benefit from the leverage of having approval to build the Polk County units.

NATURAL GAS SUPPLY AND TRANSPORTATION

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Section 11: STRATEGIC AND POLICY ASSESSMENT

INTRODUCTION

In the electric utility industry, integrated resource planning (IRP) is an activity that involves planning that must account for many complex, interrelated uncertainties and very long planning horizons. Even the most sophisticated and complex quantitative analysis cannot incorporate all of the risks and management judgments required to produce a plan that is most likely to provide maximum long-term cost effectiveness for FPC's customers. FPC's comprehensive IRP process therefore does not rely solely on a decision analysis calculation of cumulative Present Worth Revenue Requirements (PWRR), nor on its financial analysis. Consistent with its commitment to the use of IRP, Florida Power has also undertaken a strategic and policy comparison of the primary expansion plans. This section describes the main conclusions reached during this assessment.

Briefly, FPC examined the role of a number of strategic and policy considerations in strengthening or weakening the value of the Polk County combined cycle alternative. These factors included fuel supply, fuel diversity, environmental and siting benefits, the impacts of excessive reliance on external purchases, and the procurement approach. In brief, the strategic assessment reached four important conclusions:

- Even after the incorporation of the maximum feasible amount of DSM in the integrated resource plan, additional generation resources are necessary to preserve system reliability.
- Adding to FPC's generation resources by purchasing additional capacity would result in higher costs to FPC's customers than if Florida Power builds the Polk County combined cycle units. Additional purchases will adversely affect FPC's financial integrity through their impacts on credit ratings, long-run financial structure, system flexibility, and other factors.

STRATEGIC AND POLICY ASSESSMENT

- Even if Florida Power were to ignore the financial impacts of additional purchases, purchased generation is likely to cost more than the proposed Polk County units.
- The construction of the Polk County units will prompt a substantial expansion of gas pipeline capacity in the Florida peninsula.

These four factors, together with other considerations, make the Polk County combined cycle units the best and most cost-effective resource expansion option for Florida Power Corporation in the 1997-2000 time period.

OVERRELIANCE ON PURCHASED POWER

For a variety of reasons, Florida Power does not believe that it is in the interests of its customers to rely too heavily on purchased generating capacity. While none of the purchased power options Florida Power examined proved to be as cost effective as the Polk County units, FPC's strategic and policy analysis indicated that overreliance on purchases has additional disadvantages not easily reflected in Florida Power's revenue requirements calculations.

As discussed in Section 9, the financial community recognizes that capacity purchases impose long-run obligations on utilities without some of the offsetting benefits of utility-built facilities. As a result, utilities with substantial amounts of purchased power pose larger credit risks and are more likely to incur the costs of a lower credit rating.

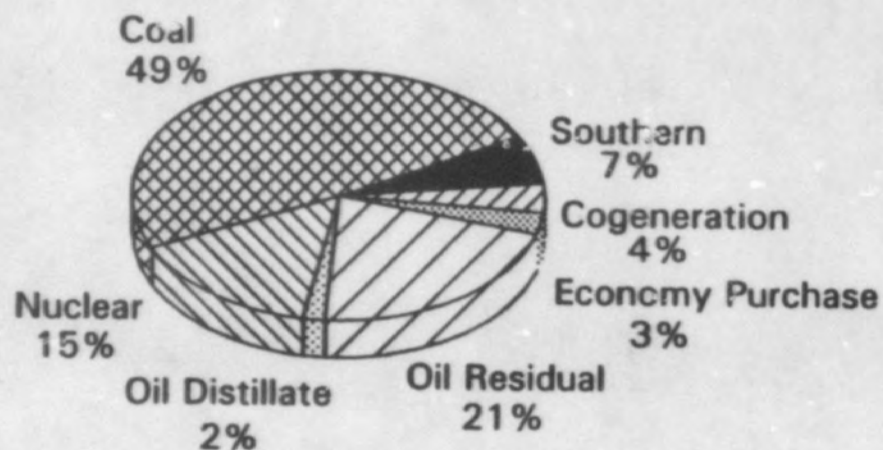
When the level of purchases is not large, the adverse impacts of purchases on a utility's credit rating are not large. However, as the amount of purchases grows, so does the negative impact of these purchases on utility credit risk.

During the past two years, FPC has aggressively purchased capacity from QFs and other sources. The level of purchases is at a point where it would not be advisable to purchase more capacity from outside sources. Figure 11.1 indicates that, on a megawatt-hour basis,

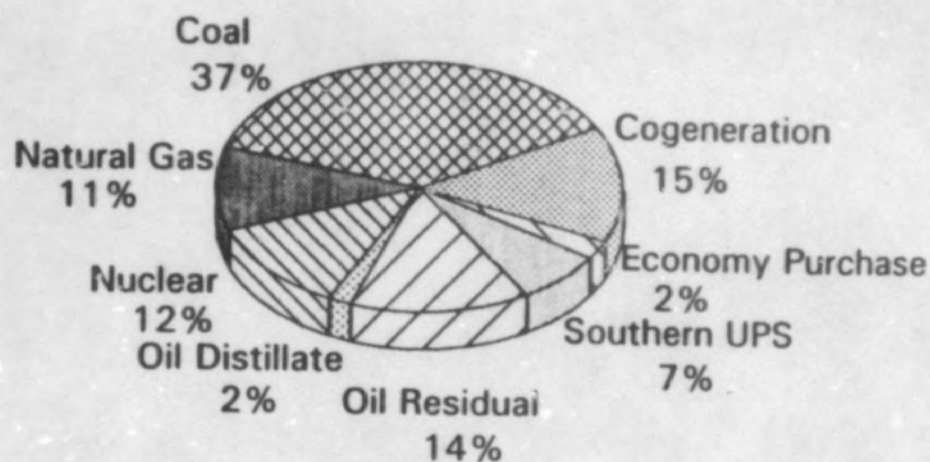
Generation Mix by Fuel Types

Alternative 3 - Combined Cycle on Gas

Figure 11.1



Fuel Types
in 1992



Fuel Types
in 2001

STRATEGIC AND POLICY ASSESSMENT

the FPC system will be purchasing almost 25% of its energy from external sources in the year 2001, i.e., *after* the installation of the four Polk County units. Larger amounts of purchases would negatively impact Florida Power's credit quality and costs of service, and therefore would not be in the interests of the FPC system and its customers.

PROCUREMENT APPROACH

Combined cycle power plants can be constructed using a number of procurement methods ranging from traditional utility construction to competitive bidding by non-utility generators (NUGs). These methods can be divided into two major categories: methods that rely on turnkey construction bids and methods wherein the utility acts as general contractor.

From the standpoint of the capital cost of the unit, there is an essential difference between these approaches. If the unit is built under a turnkey contract, such as those built by non-utility generators, all of the price risk is born by the constructor of the plant. To offset this price risk, the constructor charges a higher price. As a result, turnkey construction tends to cost more than traditional utility construction for the same size, type, and quality generating plant. This is particularly true in view of the fact that FPC has an excellent history of building generating plants on schedule and on budget.

For all of these reasons, FPC believes that dependence on outside suppliers for the generation resources called for in its plan would not be cost-effective. In spite of the many reasons why additional purchasing is not in the interests of FPC's customers, several of the alternative expansion plans analyzed in Section 8 contained substantial amounts of purchased power. These alternatives represent reasonable proxies for many of the purchased power options that would be presented to Florida Power if it were to solicit bids from interested sellers. As these options did not prove cost effective, there is no reason to believe that any option other than gas-fired combined cycle plants located in South Florida would even closely approach the costs of the Polk County units. In view of all these considerations, FPC believes that it has chosen the most cost-effective form of procurement for the most cost-effective generation expansion alternative, i.e., the combined cycle plants at the Polk County site.

STRATEGIC AND POLICY ASSESSMENT

FUEL CONSIDERATIONS

As explained in Section 10, FPC's fuel supply evaluation found that natural gas supplies were expected to remain more than sufficient to meet national demand at relatively attractive prices. Florida Power also determined that additional gas transport capability would be required to supply the Polk County plants.

From the standpoint of system fuel diversity, Alternative 3 has several attractive features. FPC's present fuel mix does not include significant amounts of natural gas, thus depriving FPC's customers of the benefits of one of the nation's most plentiful and environmentally benign fuels. Following the installation of the Polk County units, FPC's use of natural gas will change from its present level of near-zero today to a level of approximately 11% (see Figure 11.1). This will provide the system with greater insulation from fuel supply disruptions and price variability affecting any one of FPC's major fuels. The United States possesses a large, proven supply of this fuel. Unlike certain other options, the supply of natural gas is not dominated by a small number of suppliers or offshore sources.

Use of natural gas at the Polk County site provides additional system and statewide benefits in the area of fuel supply. The operation of these units will necessitate a substantial expansion of gas transport capability into Florida. When such expansion occurs, it is likely that the transport capacity created will significantly exceed the capacity required solely by the Polk County units. Additional gas supply will therefore be available for the possible conversion of other FPC generating units and for other Florida users as well. Moreover, new combined cycle units will serve as the financial anchor to a large new pipeline that otherwise may not be constructed.

ENVIRONMENTAL AND SITING BENEFITS

Florida Power Corporation places a strong emphasis on preserving the quality of the environment. This commitment begins with FPC's aggressive pursuit of demand-side management prior to the consideration of new generation and extends to the siting and operation of all of its facilities.

STRATEGIC AND POLICY ASSESSMENT

From the environmental and siting standpoint, the Polk County units offer a number of unique advantages. First, natural gas is the cleanest source of low cost fuel. As explained in Section 7 above, the use of natural gas in these units greatly facilitates FPC's compliance with the revised Clean Air Act. The use of natural gas enables FPC to comply with this Act with a minimum of costly system adjustments, and also provides substantial flexibility in the event of changes in this Act or other environmental rules.

The second environmental advantage of the combined cycle technology used by these plants is their extremely high efficiency (low heat rate). Efficient plants use smaller amounts of fuel per unit of electric service delivered and therefore create smaller environmental impacts per unit of service. Combined with the use of a clean fuel, efficient plants reduce the exposure of the FPC system to new environmental rules, constraints, or taxes.

FPC's extremely comprehensive site selection process, described in Section 12, also led to a positive assessment of the Polk County combined cycle option. The Polk County site is a mined-out area that already possesses much of the geographic infrastructure needed for major generating stations. Furthermore, the site is relatively central to the location of loads in FPC's service area. This reduces transmission losses and also reduces systemwide transmission reinforcements required to integrate these plants into the system.

BALANCING INNOVATION AND PROVEN RELIABILITY

The combined cycle units to be installed at the Polk site represent a tested, yet improving technology. These advanced combined cycle units are produced by established vendors and do not have the same operating uncertainties as less proven technologies such as pressurized fluidized bed units. They represent an excellent balance between proven technologies with little technological risk over past plants and unproven technologies that may not provide reliable service to FPC's customers.

STRATEGIC AND POLICY ASSESSMENT

FLEXIBILITY

One important advantage of the Polk County units is the flexibility they bring with respect to planning and operations. Although it is possible that capacity purchase agreements can allow for delivery alterations, the flexibility afforded by such provisions can be costly and does not offer the same ability to integrate DSM, transmission, and generation activities on a systemwide basis.

FPC dispatches, commits, and maintains its own generators so as to provide reliable service at minimum systemwide cost. While some of these activities can be partially under FPC's control through purchased sources, this partial control does not afford the FPC system the same flexibility that it retains with its own units. As the number and type of operating constraints accumulates, the FPC system becomes more costly to operate and maintain.

Finally, these Polk County combined cycle units would provide Florida Power with the flexibility to convert to coal gasification in the future should circumstances warrant it. Not only is the site an excellent one for handling coal fuel, but the combined cycle units are very adaptable to synthetic coal derived gas.

STRATEGIC AND POLICY ASSESSMENT

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Section 12: PROJECT-SPECIFIC INFORMATION

INTRODUCTION

This section provides a more detailed description of the proposed Polk County site and combined cycle units. Florida Power Corporation's proposed Polk County generating plant consists of approximately 940 MW of advanced combined cycle generating capacity to be constructed at a site in Polk County by November 2000. The proposed site will be developed on mined-out phosphate land and has the capability of later being expanded to accommodate approximately 2,000 MW of additional capacity.

The Polk County units are to be fueled initially by natural gas as the primary fuel, with No. 2 fuel oil as backup. Future conversion to coal gasification will be considered when the economics warrant it. The selected site can accommodate the conversion to coal gas.

Florida Power intends to act as a general contractor responsible for the construction of the Polk County units. This approach will result in relatively low direct construction costs by avoiding the risk premium associated with turnkey construction. In a turnkey arrangement, the contractor is obligated to deliver a completed project for a price specified early in the project's life. Given the numerous uncertainties associated with the licensing, design, and construction of a major power project, this risk premium can be significant.

The electric transmission requirements at the Polk County site are minimal, in part due to the fact that it is located relatively close to FPC's load center in central Florida. The transmission for the 940 MW associated with this project will require reconstruction of existing lines in the immediate vicinity of the plant site.

PROJECT SPECIFIC INFORMATION

PROJECT DESIGN

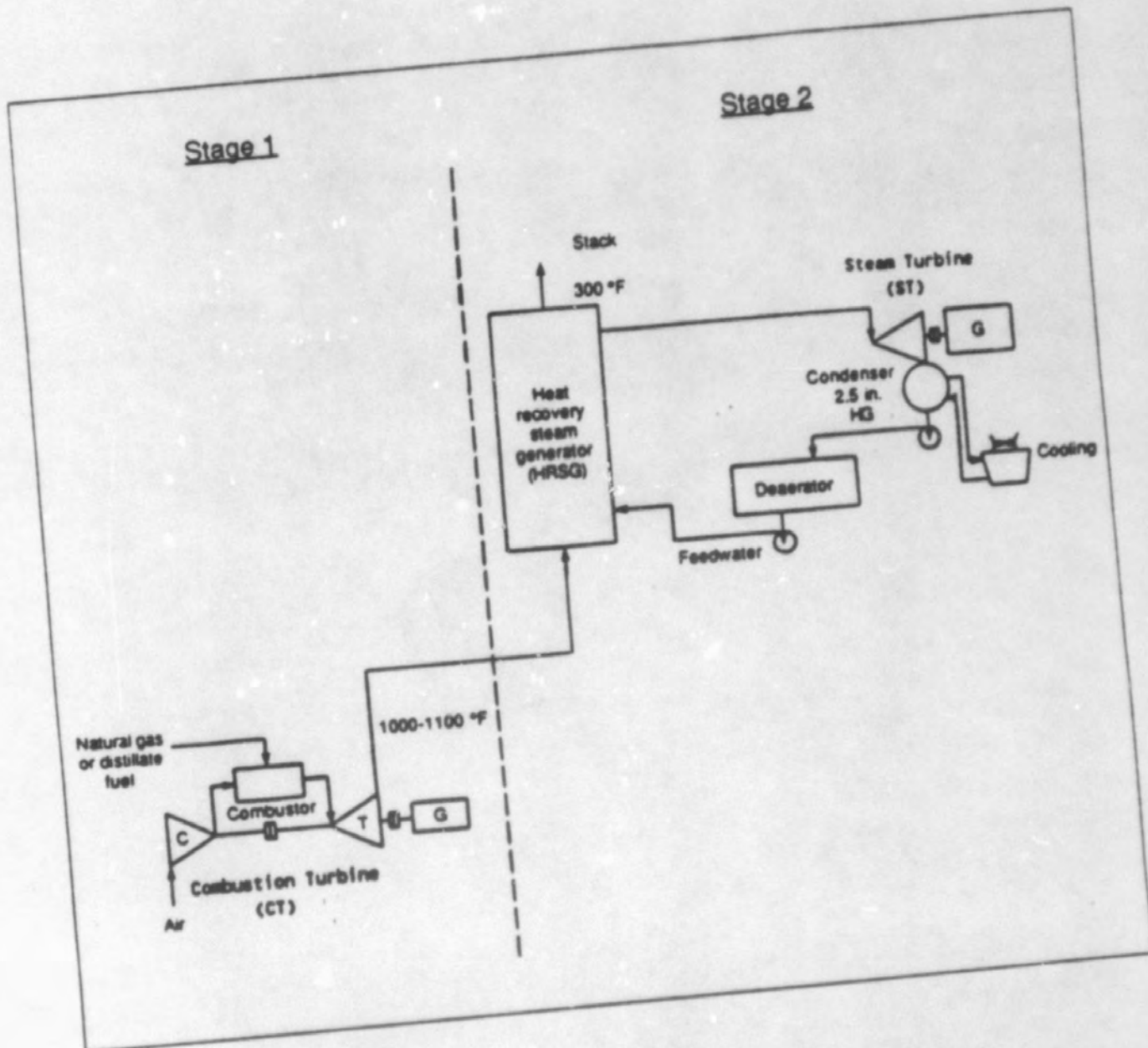
The project design process is currently in its early stages. This design is based on the use of modern, high efficiency gas-fired combustion turbines and steam turbines configured in a "combined cycle." Generating stations are referred to as combined cycle when they have two sequential generating stages (see Figure 12.1). The first stage of a combined cycle plant is a combustion turbine, much like a utility peaking plant. In the second stage of the process, the hot gas from the combustion turbine is passed through a heat recovery steam generator, where steam is produced and fed to a steam turbine. The combustion turbine and the steam turbine can be designed to drive individual generators or to drive a single generator.

In addition to capturing heat from the combustion turbine exhaust, the heat recovery steam generator can be designed for supplemental firing of natural gas or other fuels. This feature permits the production of extra steam during peak periods. Further flexibility exists through the use of reheat configurations. By reheating extracted steam, further improvements in cycle efficiency can be achieved. In sum, because combined cycle plants make excellent use of the energy in their input fuel, they have an extremely low heat rate. The modern combined cycle power plant is one of the most efficient power cycles available today.

In addition to their high efficiency, the Polk County units are being designed to have relatively low environmental impact. Airborne emissions will be limited by the use of a clean fuel and the appropriate application of control technologies. No significant solid wastes will be produced while operating on natural gas, and consumptive water use will be significantly lower than the traditional steam turbine cycles.

Another advantage of the combined cycle design is that the two stages of the plant can be configured to closely match system operating characteristics as the design process progresses. This flexibility will enable FPC to "fine tune" the design of these plants as load and system conditions become certain over the next several years.

Combined Cycle Process Diagram (Typical) Figure 12.1



PROJECT SPECIFIC INFORMATION

PROJECT COST

Although the precise final capital costs of the unit will depend on the ultimate design configuration of the plant, FPC believes that the conceptual cost estimate for the typical combined cycle unit used in this study (\$599/KW) is reasonable and conservative. As the design of the actual units progresses, estimates will be further refined, culminating in a specific cost target just prior to the start of construction.

In order to lower construction costs, FPC will rely on the general contractor method of construction, a "traditional" utility construction approach successfully used in the past. FPC will hire an architect/engineering firm to be responsible for essentially all of the detailed plant design. Manufacturers and other subcontractors will be responsible for supplying services and equipment for a well-defined fixed scope of work, thereby minimizing the risk of cost overruns.

This traditional utility approach to construction contrasts with the non-utility generator (NUG) approach relied upon by both QFs and independent power producers (IPPs). Due to the limited financing methods available to them and the absence of significant equity, NUGs generally opt for a turnkey approach to power plant construction. The amount of plant construction costs to be financed and the capacity charge to the purchasing utility must be determined at the onset of the project. The financed amount must allow not only for plant costs but for risks as well. NUGs must adjust their price upward to allow for uncertainties in escalation, change orders, schedule changes, and the cost of financing.

The major difference in the cost of the traditional approach versus the NUG approach is a function of which party is at risk. The NUG must assess the risk and include it as an adder to the base capital cost, whereas the utility, although subject to the same risk, only realizes actual costs as they occur. The NUG, in striving to protect itself, generally will include a greater percentage of contingency within the project estimate. Furthermore, the NUG will generally not participate in a project unless a significant return on equity can be realized — generally a return greater than a utility return. This too must be factored into the project estimate. Finally, the NUG may realize transactional costs greater than the utility, such as

PROJECT SPECIFIC INFORMATION

the legal and financial fees associated with the highly leveraged, nonrecourse financing undertaken by the NUG.

Crystal River Units 4 and 5 are good examples of the cost savings that can be achieved through the traditional construction approach. At \$621/KW and \$483/KW, respectively, these two units were among the lowest cost pulverized coal plants built during the last 10 years. Similarly, FPC currently is using the traditional approach to construct two 340 MW peaking projects. This approach, among other things, has allowed FPC the flexibility to procure very inexpensive turbine equipment. It is projected that the peaking project combustion turbines will be built for approximately \$266/KW and \$299/KW.

SITE SELECTION

In January 1989, FPC began the comprehensive process of locating a suitable site for a large new generation facility. Specifically, the objective of this program was to determine a primary and alternate site that would be:

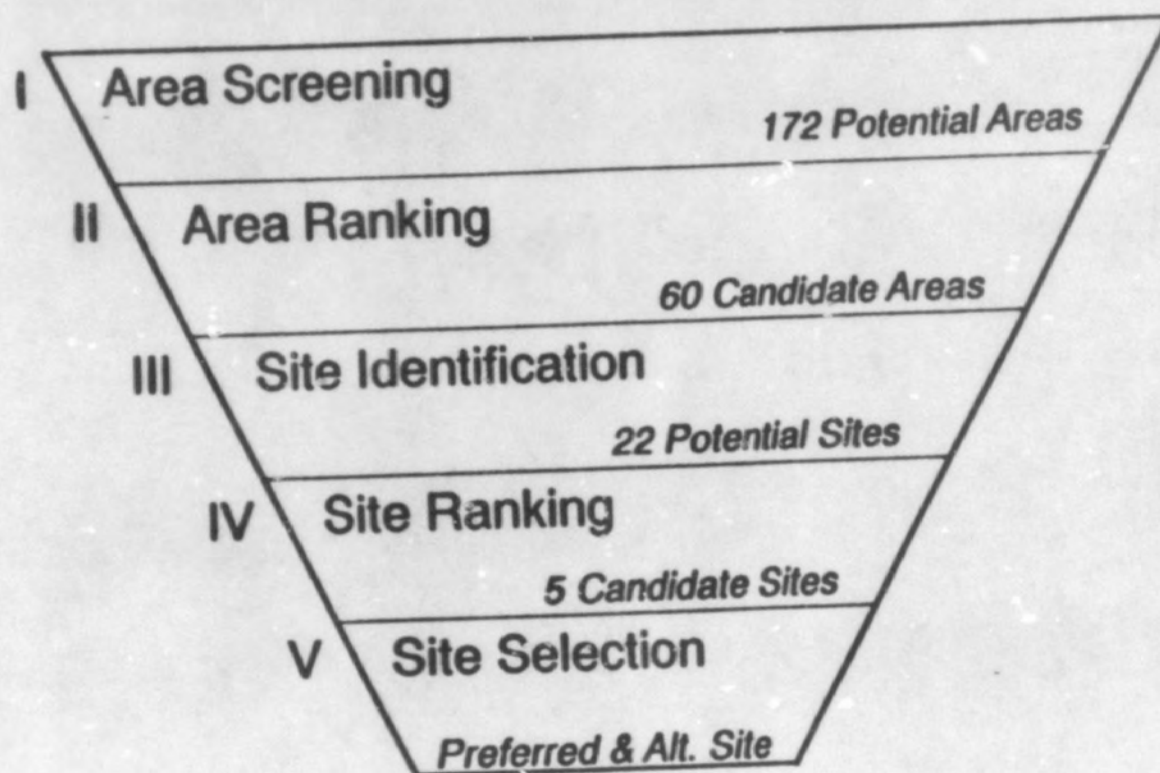
- Multi-unit and clean coal capable,
- Technology- and fuel-flexible,
- Cost effective,
- Fully compatible with FPC's commitment to environmental protection,
- In compliance with all government regulations; and
- Consistent with state land use policies.

FPC used a systematic site selection approach to ensure that all of the above concerns were fully addressed. The process involved five phases, each with a specific objective. The process (see Figure 12.2).

Phase I, Area Screening, began by screening the entire state of Florida. This phase screened out or eliminated areas that were either environmentally protected or unsuited for development of the proposed facility. Phase I concluded by defining 172 large potential areas suitable for the project.

Site Selection Process

Figure 12.2



PROJECT SPECIFIC INFORMATION

Phase II, Area Ranking, ranked the 172 potential areas using criteria that appropriately evaluated environmental, socioeconomic and engineering issues. Phase II concluded by defining the top 60 candidate areas.

Phase III, Site Identification, identified specific sites among the 60 candidate areas by conducting another screening process on a more refined geographic basis. Phase III concluded by defining 22 potential "semifinalist" sites.

Phase IV, Site Ranking, ranked the 22 semifinalist sites using advanced criteria that appropriately evaluated environmental, socioeconomic, and engineering issues. Phase IV concluded by defining the top five candidate sites.

Phase V, Site Selection, confirmed the Phase IV site ranking with additional field data and/or analytical evaluation. Phase V concluded in October 1990 by identifying the preferred and alternate sites.

Throughout this lengthy and careful process, FPC was assisted by an independent group of environmentalists, educators, and community leaders. This group, the Environmental Advisory Group (EAG), provided advice on matters of public concern. The major function of EAG was to review plans for each of the five phases of the siting process and suggest changes in the evaluation process. FPC also systematically elicited the preferences of EAG for use in the development of ranking criteria used in the evaluation process. In addition to the input received from the EAG, FPC consulted with various regulatory agencies at specific points in the process to obtain their perspective on siting criteria.

As a result of this extensive statewide search, FPC selected a location in Polk County as the primary site of its next generating unit and an alternative site in Hardee County. Both locations meet FPC's goal for a large site capable of handling staged development of various generation and fuel options. A large site is desirable in order to maximize the economies of development and long-term operation. FPC's research indicates that the site is capable of supporting approximately 3,000 MW total generation. Providing for the use of coal as a fuel ensures the flexibility to switch to gasification or other future coal based technologies as the situation dictates.

PROJECT SPECIFIC INFORMATION

THE POLK COUNTY SITE

The proposed site of the Polk County units is in the south-central portion of the county, as shown in Figure 12.3. The site consists of approximately 7,600 acres of mined and partially reclaimed phosphate property. The land is currently owned by IMC Fertilizer, Inc. and Estech, Inc.

Approximately one-half of the site acreage has been set aside for mandatory land reclamation by the Department of Natural Resources. An extensive flow connection system exists between the various clay-setting ponds on the site. Figure 12.4 depicts the existing pond arrangement, the preliminary site boundary, and the proposed location for the power plant facilities. These ponds and mined-out areas provide excellent opportunities for conversion into process cooling ponds, water retention areas, environmental habitats, and waste storage facilities. Fill material for plant facilities is available in the immediate area as a normal mining byproduct. Reclamation of the site will be coordinated with the land owners and the Department of Natural Resources in accordance with the optimum layout design.

In addition to its desirable environmental features, this site is well-suited to providing for long-term fuel flexibility. Not only can the site accommodate various generating technologies, but its geographical location places this site central to rail and pipeline fuel delivery opportunities. Two industrial grade rail lines are adjacent to the site. The CSX Bartow/Bowling Green Branchline passes on the eastern boundary, and the Mulberry/Agricola Branchline passes on the western boundary.

Figure 12.3

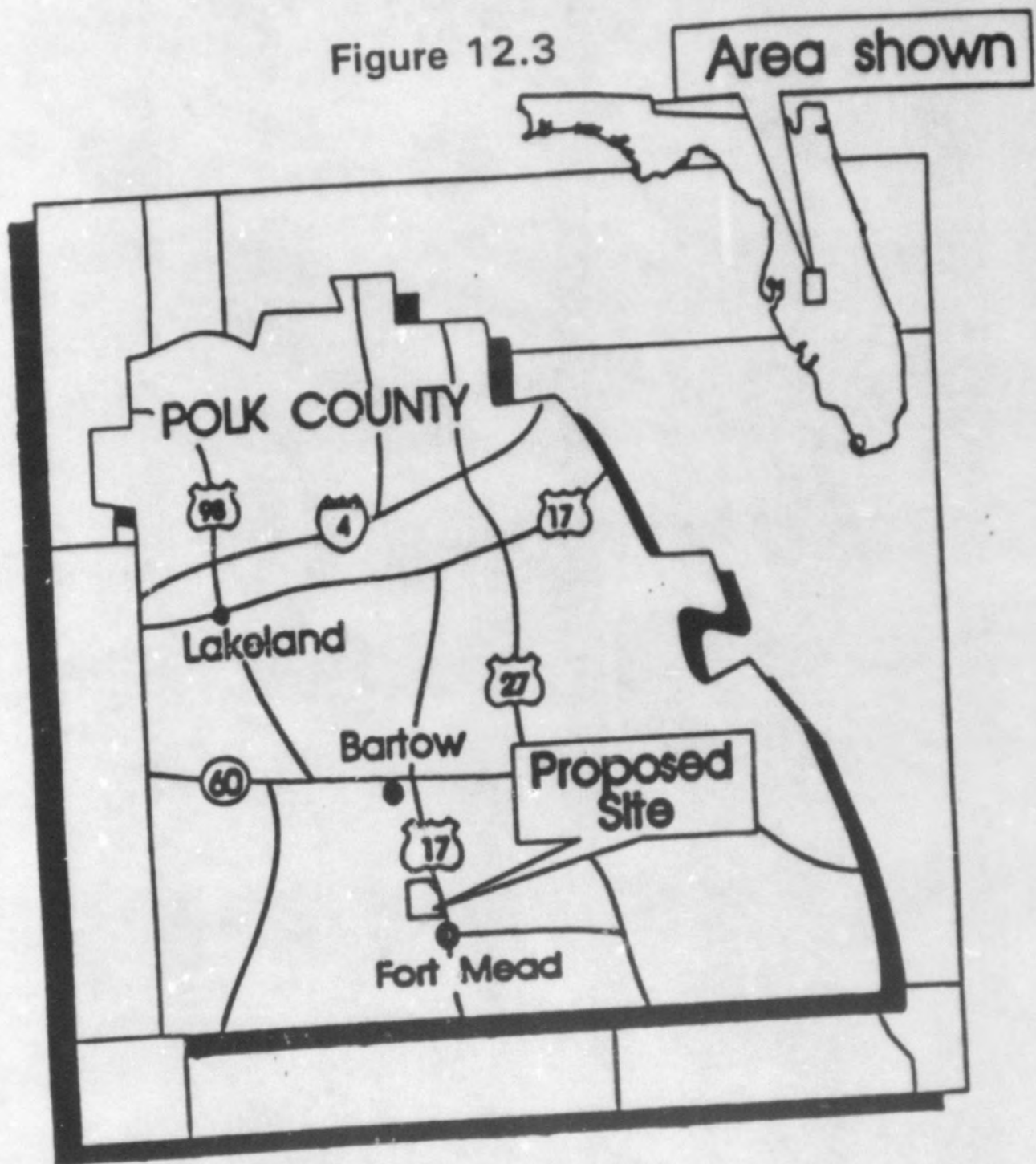
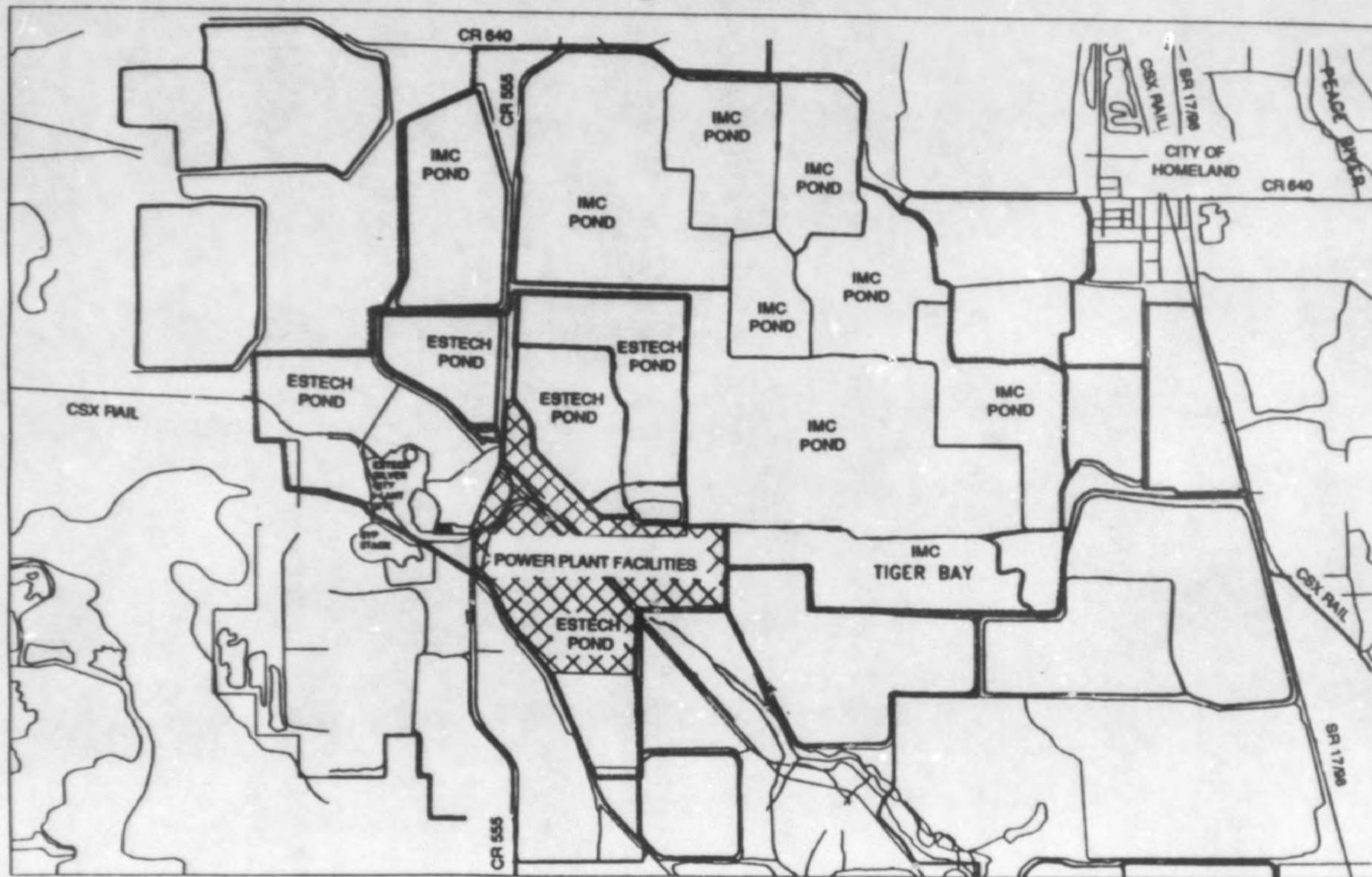


Figure 12.4

**LEGEND**

FPC SITE BOUNDARY



POWER BLOCK ISLAND



FLORIDA POWER CORPORATION
LATE NINETIES GENERATION PROJECT
POLK COUNTY SITE

PROJECT SPECIFIC INFORMATION

FUEL DELIVERY FACILITIES

Natural Gas

A pipeline capable of delivering approximately 8.5 billion BTU's per hour of pipeline quality natural gas will provide gas to the plant site. On-site facilities will include a meter station, pressure regulators, and compressors, if necessary.

No. 2 Fuel Oil

Distillate fuel oil will be used as a backup fuel when the supply of natural gas is interrupted for any reason. Since the plant will be supplied with natural gas on a firm basis, interruptions should be minimal. Therefore, storage and supply arrangements for oil will be on a much smaller scale than is required for oil-burning plants. Oil storage will provide for approximately three days of full load operation for the site. Delivery will be by transport truck from supplier terminals in the Tampa Bay Area. On-site facilities will include truck unloading stations, transfer pumps, and storage tanks.

TRANSMISSION REQUIREMENTS

For the four Polk County units, the existing Barcola-Ft. Meade 230 kV transmission line will be rebuilt and looped into the 230 kV switch yard at the plant site. The portion of the existing 230 kV transmission line from Barcola to the plant site will be rebuilt with double circuit structures to support two 230 kV circuits of 1,590 kcm ACSR conductor. The portion of the line from the plant site to Ft. Meade will require the addition of a new 230 kV circuit using 1,081 kcm ACAR conductor and will likely use the existing structures. The use of the existing structure will require the relocation of FPC's existing Ft. Meade-Rockland 115 kV circuit.

PROJECT SPECIFIC INFORMATION

PROJECT SCHEDULE

Development of a comprehensive schedule for facility design, site development, regulatory approvals, equipment procurement, construction, and other interdependent activities associated with a power plant of this size is lengthy and complex. FPC has devised an overall schedule that seeks to minimize project costs while assuring timely in-service dates for the Polk County units. FPC's preliminary schedule is set out in Figure 12.5.

Obtaining a certificate of need at a relatively early stage in development of this project is a key feature of FPC's overall schedule. Successful execution of many important elements of the project depend on prompt issuance of a need certificate.

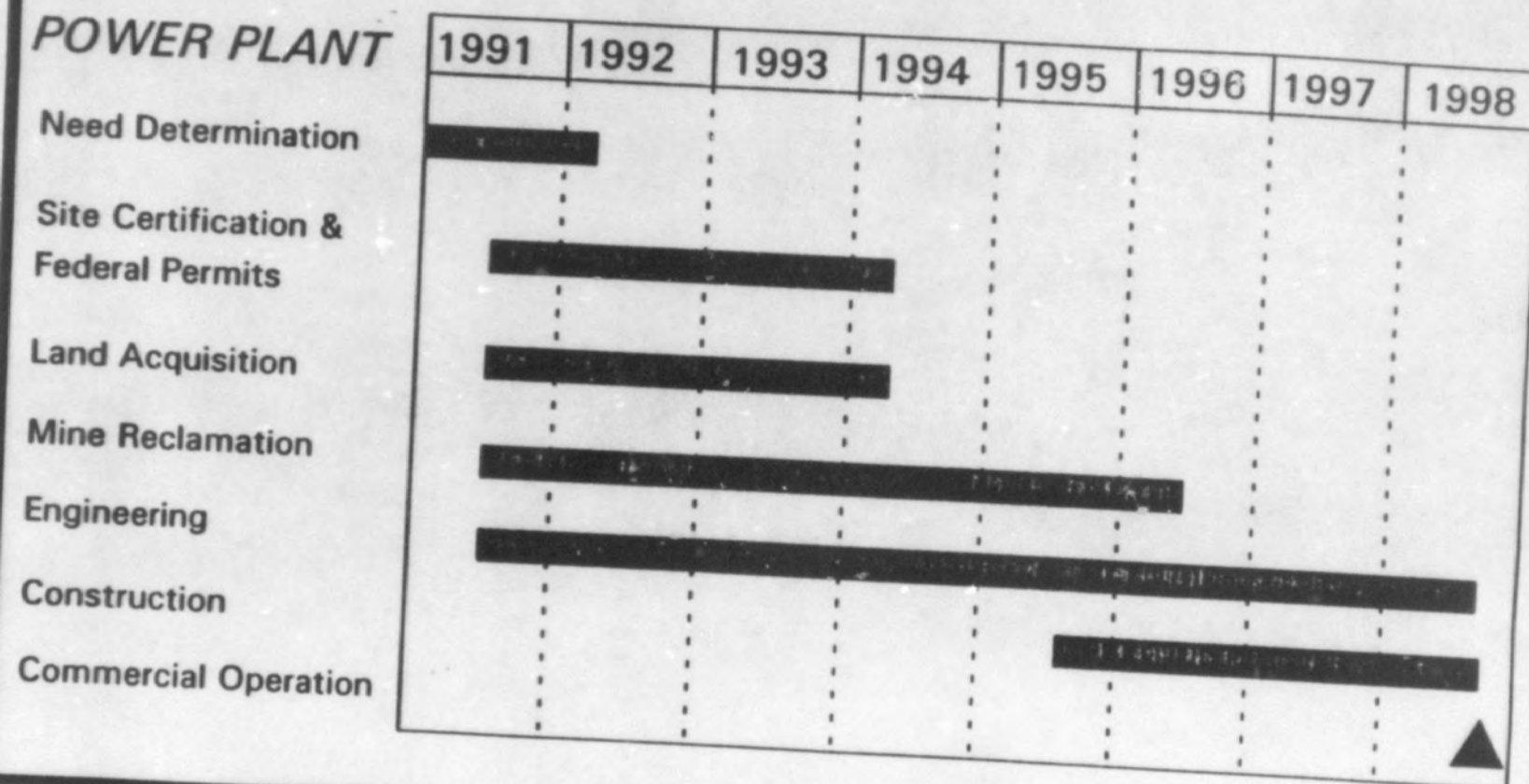
An important task that must be undertaken early on is the reclamation and reuse of the mined-out phosphate land. This is a significant engineering challenge and a critical path activity that is capable of significantly delaying commercial operation of the units. FPC is already working with landowners on their reclamation programs in order to assure that the extensive site preparation work is completed on time. Resolution of the need determination at this time will allow FPC to continue this work at reduced risk and reduced cost.

Another important benefit of establishing need early is that it will enhance FPC's ability to bring more natural gas into Florida. First, obtaining a certificate will solidify FPC's need for gas. Only after this can Florida Power make the large scale commitment that would be necessary for any gas pipeline to be built, whether by FPC or some other entity. Second, other large users of new gas transportation must be secured if a new pipeline is to be built. The ability to secure commitments from other large users would be impaired until FPC's commitment was forthcoming and FPC's share of any new gas pipeline was known. Third, obtaining low cost gas supplies, which is an integral part of any scheme to increase gas transportation capacity, will be made easier with early issuance of a need certificate.

Project Schedule (Initial Unit)

Figure 12.5

POWER PLANT



PROJECT SPECIFIC INFORMATION

Avoiding a compressed schedule for design, procurement, and construction is an important factor in keeping project costs under control. In addition, this will allow FPC the time necessary to negotiate favorable prices when procuring high cost, long-lead-time equipment and services.

Finally, prompt issuance of a need certificate will give FPC added flexibility to meet unanticipated demand. Should system demand increase at a faster rate than anticipated, or should other planned supply sources be delayed or fail to materialize (e.g., the 500 kV intertie or contracted QF supplies), FPC may be able to accelerate the overall project schedule to begin commercial operation at an earlier date.

Section 13: STATEWIDE NEED

Based on data compiled by the Florida Coordinating Group (FCG), FPC has concluded that the proposed Polk County units are consistent with statewide needs. The FCG recently published a compilation of individual utility plans and produced a summary entitled *1991 Ten-Year Plan for the State of Florida*. This plan is a compilation of the most current information and assumptions regarding the load forecasts and the existing and planned generation and bulk transmission facilities for the Florida utilities. The *Ten-Year Plan* indicates that the planned growth in statewide generation resources, including new FPC generating units and all planned QF and utility purchases, is consistent with the projected growth in firm peak demand across the state. The statewide reserve margin at the time of summer peak is expected to be 20-27% during the plan period. The state reserve margin at the time of winter peak ranges from 13-17% within the study period, after reaching a forecast low of 13% in 1998.

Although certain of FPC's planning assumptions have changed since the FCG completed this study, the net effect of these changes is to strengthen the need for the Polk County units. The new FPC generation at the proposed Polk County site in the late 1990s is about 500 MW less than the FPC new generation shown in the 1991 FCG plan.

These considerations lead FPC to conclude that the Polk County units are at least as important to statewide need as the 1991 FCG study suggests. The Polk County units are necessary for FPC to provide reliable, cost-effective service to the customers in its own service area. In addition, the construction of these units is consistent with the needs of the state of Florida.

STATEWIDE NEED

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Section 14:

CONSEQUENCES OF DELAY

INTRODUCTION

This section addresses the impact of a delay in the licensing and in-service date of the Polk County units on FPC and its customers. A delay in the in-service date of any of the units will cause FPC to violate its reliability criteria and put its customers at the risk of service interruptions. A delay in the licensing of these units will affect the ability of FPC to bring the units into service in time to meet the system loads the units are designed to serve. Such a delay could also jeopardize the introduction of significant new gas supplies into the state of Florida.

IN-SERVICE DELAY

As described in Section 7, the four combined cycle units proposed for 1998-2000 are designed to meet FPC's dual reliability criteria of 0.1 days per year LOLP and 15% winter reserve margin. Any delay that impacts the in-service date of these units must be evaluated against its effect on these criteria. In addition, the alternatives available to FPC to mitigate the consequences of the delay must be considered.

A one-year delay in the in-service date of each of the proposed units will cause FPC's winter reserve margin to drop below its minimum level of 15% in each year. Table 14.1 show that with a one-year delay, the reserve margins will range from a low of 12% in the winter of 1999/2000 to 14.5% the following winter. Further delays will have a more dramatic effect.

Impact of Delaying Construction on Polk County Units
Table 14.1

SEASON	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	FIRM * PEAK DEMAND (MW)	FIRM RESERVES	
						(MW)	(%)
Winter 1990/1991	6,571	400	112	7,083	5,834	1,249	21.4%
Summer 1991	6,192	400	135	6,727	5,559	1,168	21.0%
Winter 1991/1992	6,621	400	168	7,189	6,681	508	7.6%
Summer 1992	6,207	400	168	6,775	5,809	966	16.6%
Winter 1992/1993	6,985	400	203	7,588	6,921	667	9.6%
Summer 1993	6,511	400	356	7,267	6,046	1,221	20.2%
Winter 1993/1994	7,389	400	590	8,379	7,047	1,332	18.9%
Summer 1994	6,855	400	590	7,845	6,223	1,622	26.1%
Winter 1994/1995	7,389	400	624	8,413	7,172	1,241	17.3%
Summer 1995	6,855	400	624	7,879	6,418	1,461	22.8%
Winter 1995/1996	7,389	400	769	8,558	7,300	1,258	17.2%
Summer 1996	6,855	400	769	8,024	6,575	1,449	22.0%
Winter 1996/1997	7,389	400	769	8,558	7,422	1,136	15.3%
Summer 1997	6,855	400	769	8,024	6,727	1,297	19.3%
Winter 1997/1998	7,389	400	919	8,708	7,536	1,172	15.5%
Summer 1998	6,855	400	919	8,174	6,873	1,301	18.9%
Winter 1998/1999	7,389	400	919	8,708	7,647	1,061	13.9%
Summer 1999	6,855	400	919	8,174	7,019	1,155	16.4%
Winter 1999/2000	7,375	400	919	8,694	7,762	932	12.0%
Summer 2000	6,826	400	919	8,145	7,188	957	13.3%
Winter 2000/2001	7,785	400	919	9,104	7,950	1,154	14.5%
Summer 2001	7,176	400	919	8,495	7,365	1,130	15.3%

* Firm peak demand is forecasted demand less interruptible load.

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CONSEQUENCES OF DELAY

The drop in reserve margin puts FPC's customers at risk because there may be insufficient generation to meet their demands. While FPC would be forced to search for alternatives to meet its customers demand in any case, this Study shows that this combination of combined cycle units is the most cost-effective alternative reasonably available to meet FPC's needs in this time frame. These units have been proposed only after taking into account all reasonably available and cost-effective alternatives. This includes significant amounts of conservation and demand-side management programs, as well as firm purchases from QFs and the Southern Company. Any other alternative that might be available, even in the short term, would be more costly to FPC's customers.

A delay in the in-service date of any units beyond 1999 will also lead to an increase in FPC's sulfur dioxide emissions. Without these clean-burning, base loaded units on its system, FPC will be forced to run its less efficient, less clean units more often, resulting in an increase in emissions. This may require FPC to take more costly measures to ensure compliance with the Clean Air Act.

DELAY IN LICENSING

The impact of a delay in the licensing of the Polk County units depends on the licensing, engineering, and construction lead times necessary for the units and their fuel supply. As reflected in the project schedule in Section 12, extensive land reclamation at this site and engineering must precede the construction of these units. A significant investment is required well in advance of construction to ensure that the units will be completed on time. The timely conclusion of the licensing process under the Florida Electric Power Plant Siting Act, including the need determination, will allow these activities to proceed in a timely fashion without undue financial risk to FPC.

In addition, FPC's proposed schedule preserves the ability to bring the units on line early to meet any contingencies that might affect FPC's system reliability. These include a delay in expected QF capacity, a delay in the proposed 500 kV line, or a greater than anticipated load. Any delay in the licensing of these units would remove the important strategic flexibility offered by the proposed Polk units.

CONSEQUENCES OF DELAY

Finally, a delay in any portion of the licensing process of these units will have a severe impact on the ability to license, engineer, and construct a natural gas pipeline in the time frame necessary. As discussed in Section 10, a determination of need for these units at this time is critical to provide the necessary assurances to not only secure a firm natural gas supply, but to commit the resources necessary for additional pipeline capacity. It is critical to the success of a pipeline that FPC, as the largest potential "anchor" customer for transportation capacity, receive a need determination for the Polk County units.

Section 15:

CONCLUSION

This Integrated Resource Study has described the basis for FPC's determination that the proposed Polk County units are the most cost-effective means of providing reliable service during the latter part of the 1990s. Based on a comprehensive supply- and demand-side analysis, these four 235 MW, natural-gas-fired combined cycle units have been shown to be a necessary, efficient, economical, and environmentally sensitive addition to FPC's integrated system.

FPC's cost-effectiveness determination began with a 10-year forecast reduced by FPC's extremely aggressive demand-side management objective of 1,400 MW of load reduction by the year 2000. FPC's DSM objective highlights its commitment to meeting the energy services needs of its customers on a cost-effective basis through the use of more than 21 DSM programs, including the largest residential load management program in the United States.

In order to maintain reliable service in the FPC service area during the years 1998-2000, it is necessary to supplement Florida Power's ambitious DSM programs with additional supply-side resources. FPC has analyzed the cost effectiveness of 10 generation alternatives ranging from 700 MW pulverized coal units to additional intra- and interstate purchased capacity. These 10 alternatives were examined from the standpoint of providing the proper amount of reliability improvements, minimizing the cumulative present worth revenue requirement, and meeting FPC's emissions requirements under the revised Clean Air Act.

FPC's analysis of these factors clearly demonstrates that a series of four efficient 235 MW, natural-gas-fired combined cycle plants is the most cost-effective generation addition for the late-1990s FPC system. These high efficiency units utilize a reliable, efficient, environmentally compatible generating technology and are projected to enter service in 1998, 1999 (two units), and 2000. At an estimated cost of \$599/KW (excluding AFUDC), these plants are significantly less costly to the FPC system than all other available generation alternatives, including purchases from other utilities or non-utility generators.

CONCLUSION

Another attractive feature of the Polk County units is the fact that they will play a key role in bringing new natural gas transportation capacity to the state of Florida. These units, together with the planned conversion of existing generation, will allow FPC to make a substantial gas usage commitment. New pipeline capacity is economically feasible only when this sort of large scale commitment can be made. FPC's proposed Polk County units will also add significantly to fuel diversity, reducing FPC's dependence on any one fuel type or supplier. The fraction of generation produced from natural gas will increase from near zero today to almost 15% by the year 2001.

FPC proposes to site the four combined cycle plants on the site of a former phosphate mine in Polk County, Florida. FPC chose this site on the basis of a careful screening process that indicated that this site had many advantages, including proximity to FPC's load center, minimal additional transmission needs, ample capability to accommodate additional units or coal conversion facilities, and minimal additional environmental impacts.

FPC has rejected the concept of using additional purchases to satisfy its needs for supply-side additions. FPC has contracted to purchase more capacity from QFs than all other Florida investor-owned utilities combined, in addition to purchases from utility suppliers. While Florida Power has aggressively pursued outside purchases for the past several years, its system is now at a point where additional purchases will harm FPC's long-run financial well-being. Specifically, additional purchases will reduce Florida Power's creditworthiness and its operating and planning flexibility.

FPC construction of the Polk County units is also desirable because it is cheaper than all other options examined, including non-utility generation. FPC has a proven ability to manage plant construction on time and on budget, and the nature of non-utility construction methods tends to lead to prices at least as high as those of utilities. For all of these reasons, FPC believes that it would not be prudent or cost effective to solicit bids for additional capacity from outside suppliers.

In sum, FPC's Integrated Resource Plan, including the Polk County units, represents a cost-effective means of meeting the energy service needs of the customers of Florida Power Corporation. These Polk County units are also consistent with the statewide need to build

CONCLUSION

additional cost-effective, efficient, environmentally sound generating capacity to serve Florida's electrical energy needs well into the 21st century.

CONCLUSION

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Appendix A:
LOAD FORECAST, DEMAND, AND
ENERGY FORECASTS AND ASSUMPTIONS

APRIL 1991 LONG-TERM FORECAST ASSUMPTIONS

1. Normal weather conditions. Normal weather is based on a 10-year average of service area weighted degree days for comparison with kilowatt-hour sales. A 10-year average service area weighted temperature during the hour of system peak is used for comparison with kilowatt peak demand.
2. The population projections produced by the Bureau of Economic and Business Research (BEBR) at the University of Florida provide the basis for development of the customer forecast. This forecast uses "Population Studies," Bulletin No. 92, February 1990.
3. Energy sales to the phosphate industry in 1990 plunged 22.1% from 1989 levels due to the closing of two Polk County mines, a curtailment of energy consumption at Occidental Corporation, and a transfer of phosphate load to TECO. The decline in energy sales to the phosphate industry should bottom out by mid-year 1991 as the effect of the double mine shut down reaches the end of its first full year. Following this mid-1991 trough, the forecast anticipates an increase in phosphate energy usage, including a return of Occidental's energy use to pre-curtailed levels by 1992. Further changes are not expected to occur until 1994, when new mining operations in Hardee County will initiate a surge in phosphate mining activity and energy usage. In the longer term, phosphate energy sales are expected to remain constant at the mid-1990s level.
4. The status of Florida Power Corporation's (FPC) wholesale load and energy service to Seminole Electric Cooperative Incorporated and Florida Municipal Power Agency is assumed to remain unchanged throughout the forecast period. This forecast accounts for the addition of New Smyrna Beach as a new partial requirements customer beginning in June 1992.

LOAD FORECAST, DEMAND, AND ENERGY FORECASTS AND ASSUMPTIONS

5. The forecast contains the effects of FPC's energy conservation and marketing programs on KWh energy sales and KW peak demand.
6. The energy and demand impacts expected from cogeneration are subtracted from the forecast. FPC will supply the net load of future cogeneration customers. Net load is defined as the cogeneration customers' native load less their generation output.
7. The economic outlook for this 20-year forecast attempts to describe both the short-term outlook for the current economic business cycle as well as the long-term trend for the economy, particularly with respect to their impact upon Florida Power Corporation's customers, sales, and demand. It is important to note, however, that identification of the long-term trend in economic/demographic conditions represents the main focus of this forecast. The purpose of the short-term outlook is only to show how the current business cycle is expected to evolve and eventually blend into the long-term. Beyond the short-term time horizon, only the trends in economic and demographic conditions which cut through the peaks and troughs of future business cycles are considered in this forecast.

SHORT TERM

The basis for this customer, energy, and demand forecasts during the first five years of this 20- year forecast reflect the current economic recession which began in the latter half of 1990. Brought on by the Middle East crisis and subsequent run up in oil prices and suppressed consumer confidence, this recession also owes its existence in part due to a tightening of credit availability among financial institutions. This short-term weakness in the national economy has significantly affected population and job growth in the Florida economy. Unstable economic conditions as well as weak real estate markets in the northeast U.S. have limited the mobility of those seeking to move to Florida. Also, the desire to come to Florida may have weakened as the state's unemployment rate has remained consistently higher than the national rate since mid-1989.

LOAD FORECAST, DEMAND, AND ENERGY FORECASTS AND ASSUMPTIONS

The economic recovery is expected to begin by mid-year 1991 and will be in full swing by 1992. However, it will also be relatively weak by historical standards since no government anti-recession stimulus is expected. Other reasons for a weak recovery include the high debt levels in both the public and private sectors of the economy, and the weak financial condition of many lending institutions nationwide. Until debt levels return to normal ranges and banks shore up their financial condition, consumer spending and private investment will not exhibit the post-recessionary strength necessary to stimulate a typical recovery for the U.S. economy. On the positive side, the recovery will be driven by lower oil prices, lower inflation, and lower interest rates. Healthier real estate markets will help boost Florida's population growth and promote an improved job picture.

LONG TERM

The longer term (1995-2010) economic scenario assumes that changes in economic and demographic conditions will follow a general trend. No attempt is made to predict business cycle fluctuations during this period. The main focus involves identifying long-term economic and demographic trends.

Population Growth Trends

This forecast assumes Florida will experience slower in-migration and population growth over the long-term, as captured in the BEBR projections.

- o Florida's climate and low cost of living have historically attracted a major share of the retirement population from the eastern half of the United States. This will continue to occur but at less than historical rates for two reasons. First, Americans entering retirement age during the 1990s were born during the Great Depression era of the 1930s. This decade experienced a low birth rate due to the economic conditions at that time. Sixty years later, there now exists a smaller pool of retirees capable of moving to Florida. Second, the enormous growth in population and development of the 1980s has left parts of Florida unenviable for retirement living. This diminished quality of retiree life along with increasing

LOAD FORECAST, DEMAND, AND ENERGY FORECASTS AND ASSUMPTIONS

competition from neighboring states for the retirement population is expected to cause a slight decline in Florida's share of these prospective new residents over the long-term.

- With the bulk of Florida's in-migrants under age 45, the baby boom generation born between 1945 and 1960 helped fuel the rapid population increase Florida experienced during the 1980s. Coupling this with two other events of the 1980s - airline deregulation which lowered airfares increasing accessibility to Florida, and a recession in the oil-producing states which historically has pulled a percentage of its labor pool from Florida - one begins to realize that these conditions will not reoccur in the foreseeable future. In fact, slower population in-migration to Florida can be expected as the baby boom generation enters the late 40s and 50s age bracket. This age cohort has been significantly characterized as immobile when studies concerning interstate population flows or job changes are conducted.

Economic Growth Trends

- Florida's rapid population growth of the 1980s created a period of strong job creation, especially in the service sector industries of the state economy. While the service-oriented economy expanded to support the increasing population level, there was also significant numbers of corporations migrating to Florida capitalizing on the low cost/low tax business environment. In this situation, increased job opportunities in Florida created greater in-migration among the nation's working age population. Florida's ability to attract businesses from other states because of its "comparative advantage" is expected to continue throughout the forecast period. While the years may be numbered before Florida passes a statewide tax plan, it will still be more favorable than tax levels in many of the population "sending states". Lower land and/or expenses are also expected to remain an attractive business advantage in Florida.
- The forecast assumes no growth in real, i.e., constant dollar, electricity prices. That is, changes in the nominal, or current dollar, price of electricity over time is expected to track the overall rate of inflation. This also implies that no energy supply interruptions are predicted to impact electricity prices throughout the forecast horizon.

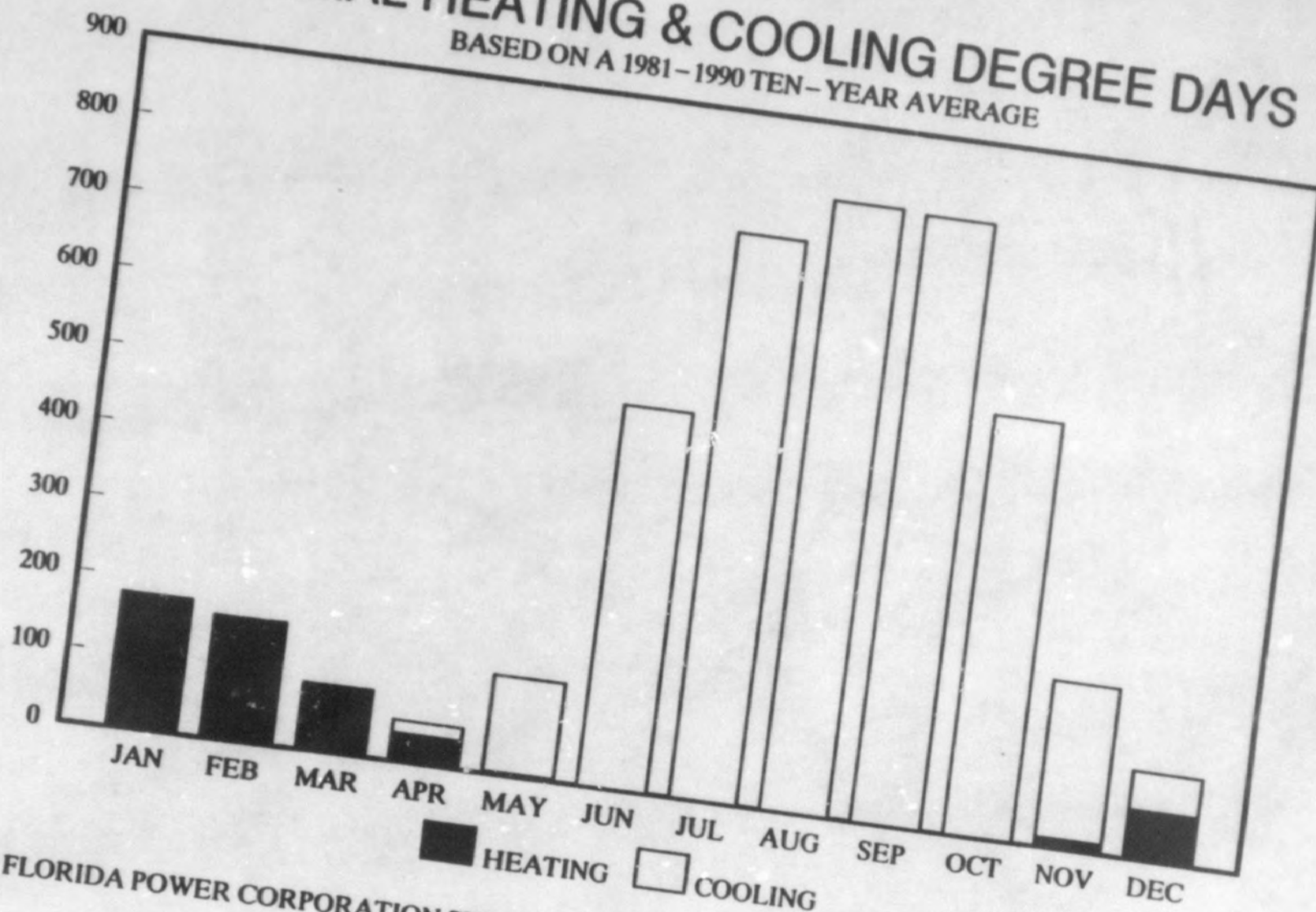
LOAD FORECAST, DEMAND, AND ENERGY FORECASTS AND ASSUMPTIONS

- Real per capital personal incomes are assumed to increase throughout the forecast period and thereby boost the average customer's ability to purchase electricity - especially since the price of electricity is only expected to increase at a rate equal to the consumer price index. As incomes grow faster than electricity costs, consumers' ability to make additional purchases will improve.

FORECAST ASSUMPTIONS

NORMAL HEATING & COOLING DEGREE DAYS

BASED ON A 1981-1990 TEN-YEAR AVERAGE



FLORIDA POWER CORPORATION SERVICE AREA WEIGHTED, BILLING MONTH DATA.

FPC SERVICE - AREA WEIGHTED BILLING - MONTH HEATING DEGREE DAYS

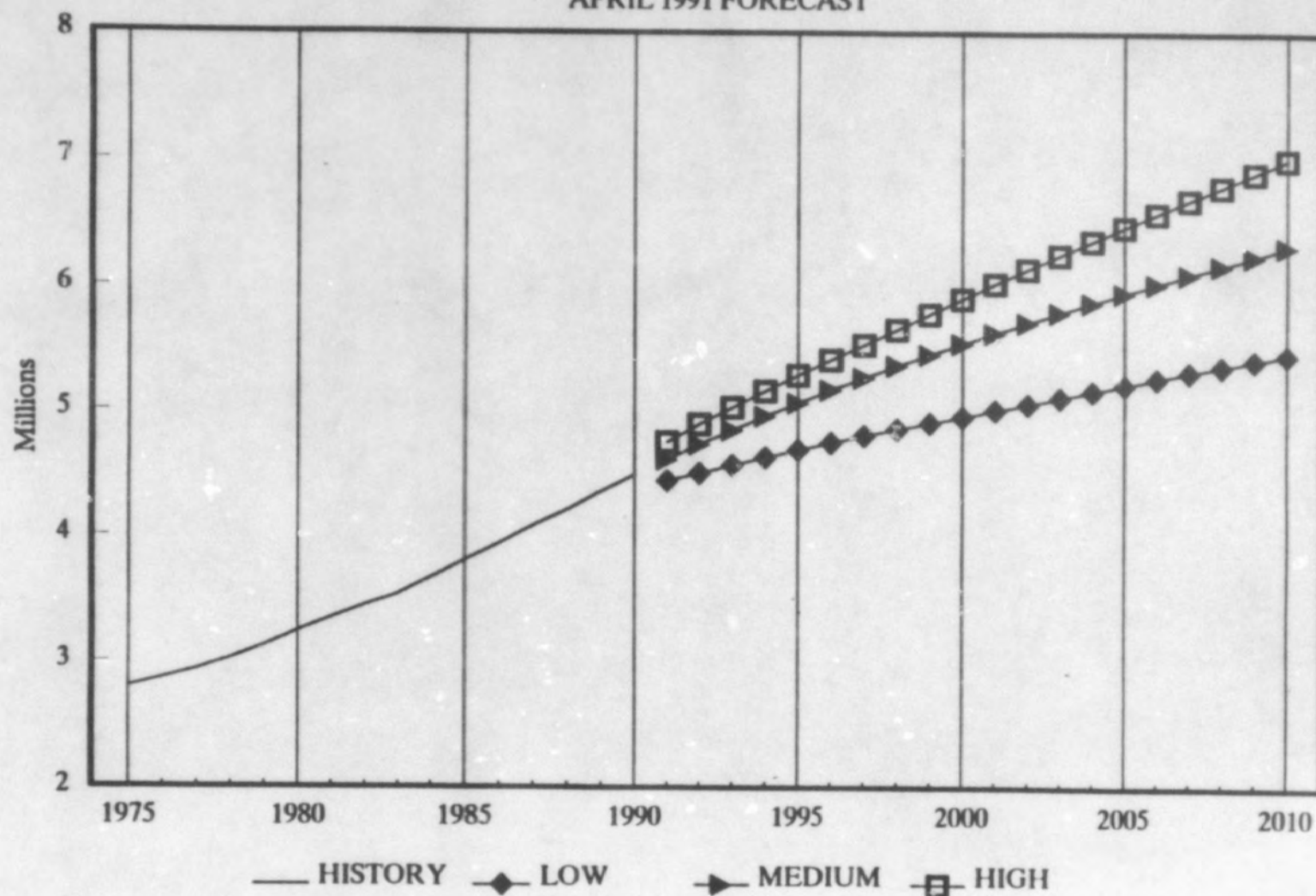
	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1981 - 1990 AVERAGE
JAN	326	178	140	267	107	210	103	128	76	230	177
FEB	268	107	193	191	256	143	142	223	42	50	162
MAR	62	36	114	109	87	112	59	135	128	33	88
APR	44	15	74	37	18	47	62	50	24	13	38
MAY	1	2	10	11	3	6	0	3	1	3	4
JUN	0	0	0	0	0	0	0	0	0	0	0
JUL	0	0	0	0	0	0	0	0	0	0	0
AUG	0	0	0	0	0	0	0	0	0	0	0
SEP	0	0	0	0	0	0	1	1	3	0	1
OCT	1	1	0	1	0	0	12	5	22	14	13
NOV	16	25	11	18	6	2	68	72	105	48	65
DEC	123	34	59	80	43	16					
TOTAL	841	398	601	714	520	536	447	617	401	391	548

FPC SERVICE - AREA WEIGHTED BILLING - MONTH COOLING DEGREE DAYS

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1981 - 1990 AVERAGE
JAN	0	0	0	0	0	0	0	0	0	0	0
FEB	0	0	0	0	0	0	0	0	0	0	0
MAR	0	0	0	0	0	0	0	0	0	0	0
APR	33	36	18	13	0	16	7	13	20	4	16
MAY	136	91	39	177	146	80	102	118	165	194	125
JUN	556	480	445	363	540	525	525	354	603	619	501
JUL	777	742	738	645	742	731	852	700	760	735	742
AUG	857	763	797	748	769	829	870	740	793	830	800
SEP	734	782	789	737	728	812	859	869	846	812	797
OCT	499	512	483	356	576	699	517	562	640	642	549
NOV	174	127	237	228	447	294	79	48	155	251	204
DEC	5	23	11	16	157	204	19	54	2	11	50
TOTAL	3771	3556	3557	3283	4105	4190	3830	3458	3984	4098	3784

FPC 32—COUNTY POPULATION

APRIL 1991 FORECAST

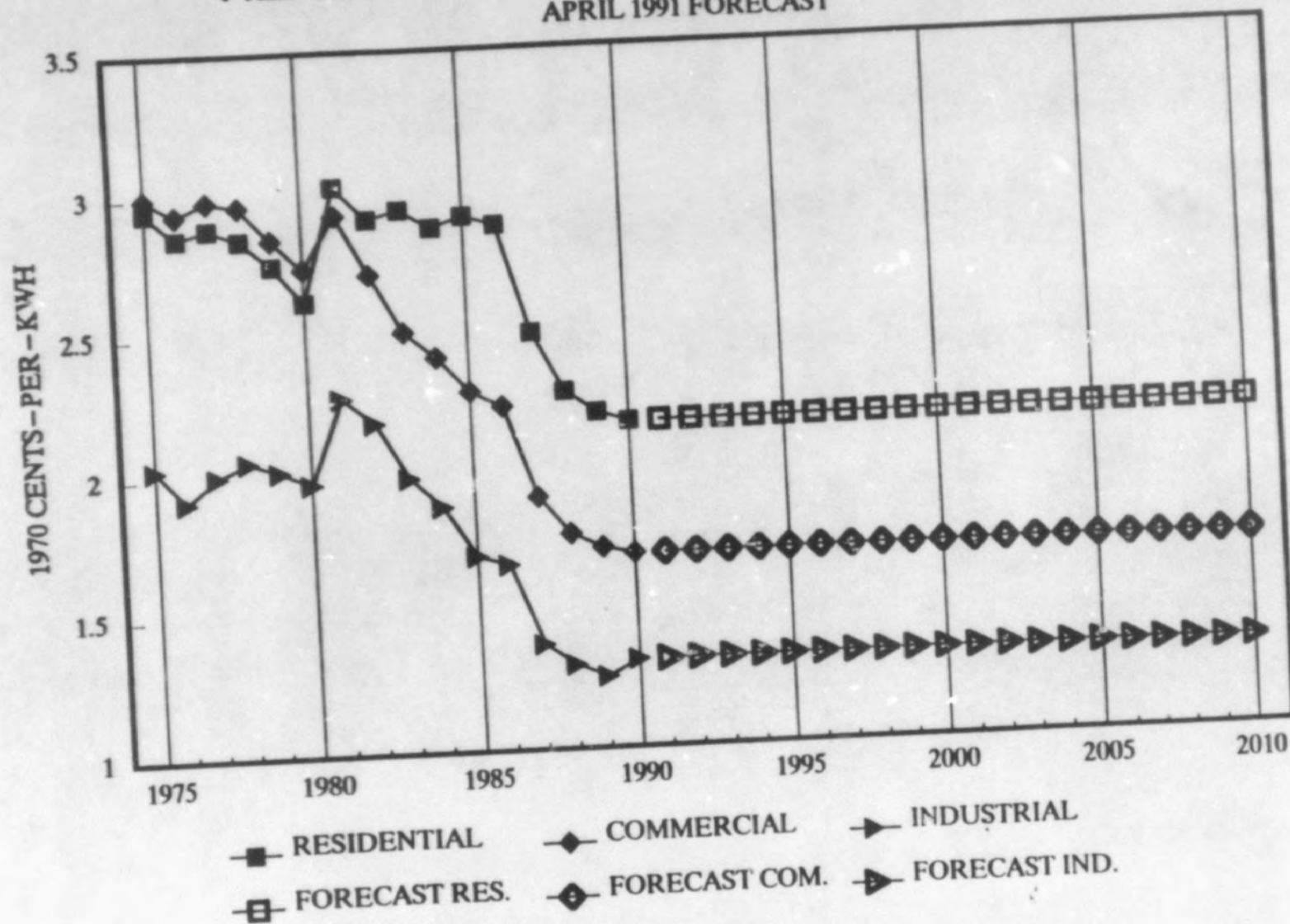


FLORIDA POWER CORPORATION 32-COUNTY POPULATION

		YEAR	ESTIMATES			
HISTORY:		1975	2,796,900			
		1976	2,863,500			
		1977	2,933,200			
		1978	3,020,100			
		1979	3,121,700			
		1980	3,240,098			
		1981	3,342,554			
		1982	3,442,572			
		1983	3,529,568			
		1984	3,662,070			
		1985	3,802,724			
		1986	3,940,524			
		1987	4,078,202			
		1988	4,207,222			
		1989	4,354,135			
		1990	4,482,500			
		1975-1990 AAGR	3.19			
FORECAST:	YEAR	LOW	% DIFF	MEDIUM	% DIFF	HIGH
	1991	4,434,701	-3.74	4,606,874	3.01	4,745,610
	1992	4,497,959	-4.85	4,727,059	3.42	4,888,663
	1993	4,560,309	-5.83	4,842,857	3.76	5,024,716
	1994	4,621,705	-6.71	4,954,070	4.03	5,153,769
	1995	4,682,192	-7.48	5,060,500	4.30	5,278,336
	1996	4,740,093	-8.17	5,162,067	4.62	5,400,338
	1997	4,795,908	-8.81	5,259,167	4.99	5,521,840
	1998	4,848,368	-9.42	5,352,313	5.44	5,643,342
	1999	4,897,389	-10.01	5,442,019	5.93	5,764,845
	2000	4,946,077	-10.54	5,528,800	6.46	5,885,848
	1991-2000 AAGR	1.22		2.05		2.42
	2001	4,995,401	-11.01	5,613,132	7.00	6,005,928
	2002	5,046,292	-11.40	5,695,346	7.53	6,124,286
	2003	5,098,222	-11.73	5,775,733	8.04	6,239,864
	2004	5,150,659	-12.02	5,854,587	8.51	6,352,607
	2005	5,203,076	-12.29	5,932,200	8.96	6,463,457
	2006	5,254,942	-12.55	6,008,865	9.39	6,572,856
	2007	5,305,727	-12.80	6,084,875	9.80	6,681,248
	2008	5,354,902	-13.08	6,160,522	10.20	6,789,076
	2009	5,401,938	-13.38	6,236,100	10.59	6,896,782
	2010	5,446,304	-13.71	6,311,900	10.98	7,004,809
	2001-2010 AAGR	0.96		1.31		1.72
1991-2010 AAGR		1.09		1.67		2.07

REAL PRICE OF ELECTRICITY (1970 \$)

APRIL 1991 FORECAST

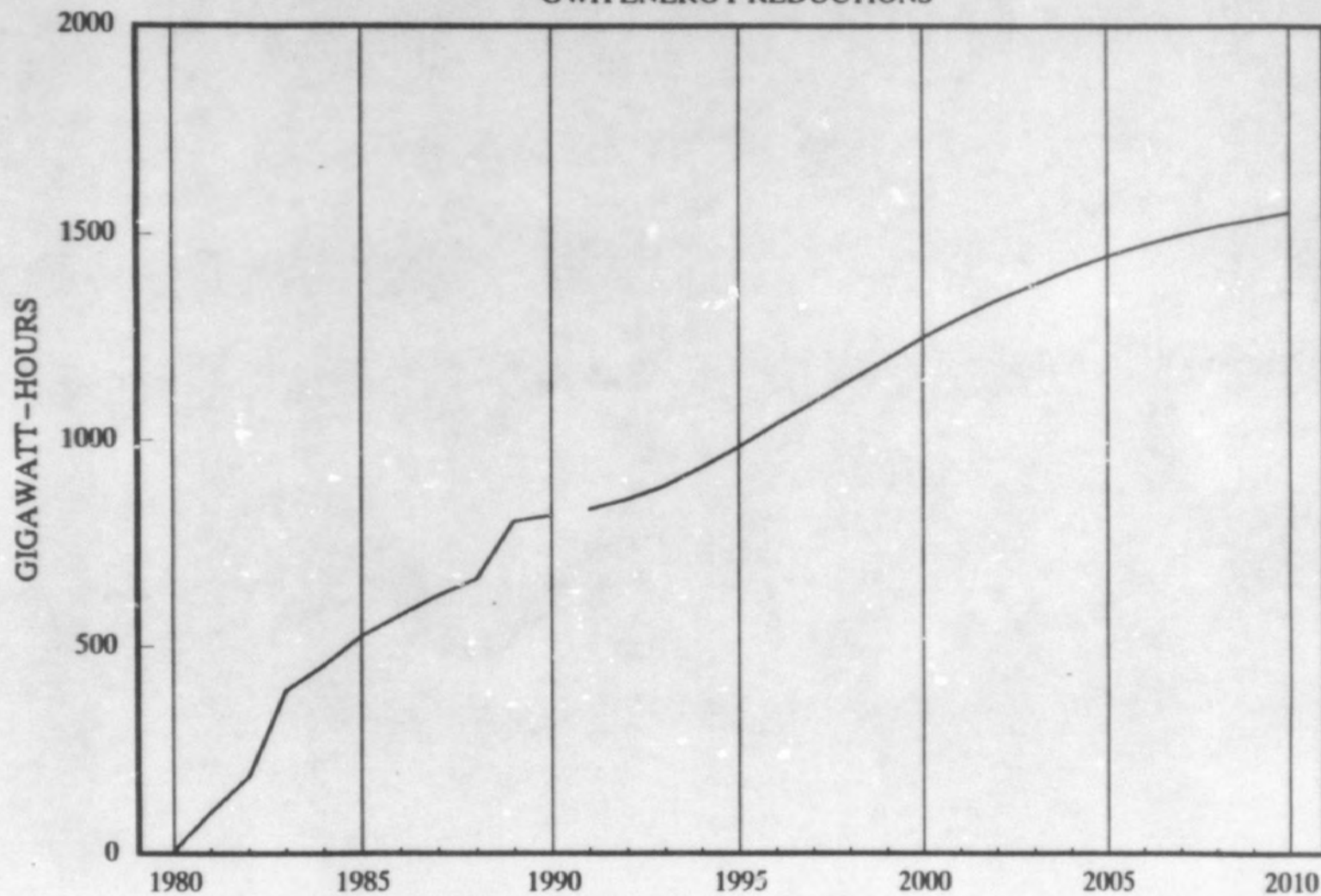


FLORIDA POWER CORPORATION REAL PRICE OF ELECTRICITY
(CENTS-PER-KILOWATT-HOUR IN 1970 \$)

	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL
HISTORY:	1975	2.95	3.00	2.03
	1976	2.86	2.94	1.92
	1977	2.89	2.98	2.00
	1978	2.84	2.96	2.05
	1979	2.75	2.84	2.01
	1980	2.62	2.74	1.97
	1981	3.03	2.92	2.27
	1982	2.91	2.71	2.18
	1983	2.94	2.50	1.98
	1984	2.87	2.41	1.87
	1985	2.91	2.28	1.69
	1986	2.87	2.23	1.66
	1987	2.49	1.90	1.37
	1988	2.27	1.76	1.30
	1989	2.19	1.71	1.25
	1990	2.16	1.69	1.31
1975-1990 AAGR		-2.06	-3.77	-2.89
FORECAST:	1991	2.16	1.69	1.31
	1992	2.16	1.69	1.31
	1993	2.16	1.69	1.31
	1994	2.16	1.69	1.31
	1995	2.16	1.69	1.31
	1996	2.16	1.69	1.31
	1997	2.16	1.69	1.31
	1998	2.16	1.69	1.31
	1999	2.16	1.69	1.31
	2000	2.16	1.69	1.31
1991-2000 AAGR		0.00	0.00	0.00
	2001	2.16	1.69	1.31
	2002	2.16	1.69	1.31
	2003	2.16	1.69	1.31
	2004	2.16	1.69	1.31
	2005	2.16	1.69	1.31
	2006	2.16	1.69	1.31
	2007	2.16	1.69	1.31
	2008	2.16	1.69	1.31
	2009	2.16	1.69	1.31
	2010	2.16	1.69	1.31
2001-2010 AAGR		0.00	0.00	0.00
1991-2010 AAGR		0.00	0.00	0.00

ENERGY CONSERVATION PROGRAM IMPACTS

GWH ENERGY REDUCTIONS



ENERGY CONSERVATION PROGRAMS GWH REDUCTIONS

YEAR	ENERGY MANAGEMENT			RESIDENTIAL PROGRAMS					
	COGEN	LOAD MANAGEMENT	VOLTAGE REDUCTION	ENERGY SAVER	SUPER SAVER	EDUCATION	HOME ENERGY ANALYSIS	HOME ENERGY CHECKUP	HOME ENERGY FIXUP
HISTORY									
1980	7.00								
1981	78.00	0.00							
1982	126.00	0.00	0.08						
1983	271.00	1.08	0.28						
1984	268.00	5.44	0.47	0.00					
1985	281.00	8.02	0.68	8.85	0.00	0.00			
1986	290.00	11.24	0.87	17.01	0.00	10.81	0.00		
1987	308.00	13.45	0.97	30.43	0.00	11.18	1.90	0.00	0.00
1988	310.00	15.00	1.00	35.79	12.13	11.40	3.98	1.75	0.03
1989	423.00	25.24	1.00	35.79	23.28	12.06	5.25	5.74	3.49
1990	423.00	28.67	1.07	35.79	31.31	12.57	6.01	10.49	9.00
		30.74	1.12	35.79	31.31	13.06	6.38	16.18	14.38
			1.16	35.79	31.31	13.58	6.54	22.45	18.05
				35.79	31.31	14.12	6.57	28.76	21.39
				35.79	31.31	14.57	6.58	33.56	23.74
					31.31	0.00	6.59	38.21	25.85
							6.65	43.31	28.94
								48.11	31.58
FORECAST									
1991									
1992	423.00	36.77							
1993	424.00	42.63	1.20						
1994	423.00	49.03	1.23						
1995	423.00	55.42	1.29	35.79	31.31				
1996	423.00	61.81	1.33	35.79	31.31	0.00			
1997	424.00	68.20	1.38	35.79	31.31	0.00	6.69		
1998	423.00	74.59	1.42	35.79	31.31	0.00	6.74	49.28	33.20
1999	423.00	80.99	1.47	35.79	31.31	0.00	6.79	51.13	36.16
2000	423.00	87.38	1.51	35.79	31.31	0.00	6.84	52.98	39.11
2001	424.00	91.00	1.55	35.79	31.31	0.00	6.89	54.83	42.06
2002	423.00	92.63	1.59	35.79	31.31	0.00	6.94	56.68	45.02
2003	423.00	94.27	1.63	35.79	31.31	0.00	6.99	58.53	47.97
2004	423.00	95.91	1.67	35.79	31.31	0.00	7.04	60.38	50.93
2005	424.00	97.55	1.70	35.79	31.31	0.00	7.09	62.23	53.88
2006	423.00	99.18	1.74	35.79	31.31	0.00	7.14	64.08	56.83
2007	423.00	100.82	1.78	35.79	31.31	0.00	7.19	65.93	59.79
2008	423.00	102.46	1.83	35.79	31.31	0.00	7.24	67.78	62.74
2009	424.00	104.09	1.85	35.79	31.31	0.00	7.29	69.63	64.85
2010	423.00	105.73	1.89	35.79	31.31	0.00	7.34	71.48	66.54
	423.00	107.37	1.94	35.79	31.31	0.00	7.39	73.33	68.23
			1.96	35.79	31.31	0.00	7.44	75.18	69.92
					31.31	0.00	7.49	77.03	70.97
						0.00	7.54	78.88	72.03
						0.00	7.59	80.73	73.08
						0.00	7.64	82.58	74.14
								84.43	75.19

**ENERGY CONSERVATION PROGRAMS
GWH REDUCTIONS**

YEAR	RESIDENTIAL PROGRAMS (CONT'D)							COMMERCIAL/INDUSTRIAL PROGRAMS		
	RES. HEATWORKS	RES. COMFORT CASH LOAN	RES. A/C DUCT TEST & REPAIR	RES. INSULATION UPGRADE	RES. A/C ALLOWANCE	RES. A/C SERVICE	RES. TRADE EFFICIENCY	E.C. DESIGN AWARD	BUSINESS ENERGY CHECKUP	BUSINESS ENERGY ANALYSIS
HISTORY										
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.42
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.94	0.34	7.50
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.26	3.60	17.90
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.46	7.54	30.83
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.32	12.39	44.64
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.94	16.22	49.32
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.41	20.03	53.95
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.03	23.39	55.81
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.53	30.96	61.36
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.53	39.87	66.83
FORECAST										
1991	0.00	0.22	0.45	0.87	0.68	0.12	0.24	39.53	41.24	67.30
1992	-0.44	0.57	1.45	2.47	3.18	0.26	0.96	39.53	43.86	68.27
1993	-0.94	1.07	3.70	5.67	10.68	0.46	1.69	39.53	46.49	69.25
1994	-1.56	1.57	10.95	12.15	22.18	0.78	2.41	39.53	49.11	70.22
1995	-2.31	2.07	18.20	18.63	37.68	1.20	3.14	39.53	51.74	71.20
1996	-2.31	2.57	25.45	25.11	55.18	1.70	3.49	39.53	54.36	72.17
1997	-2.31	3.07	32.70	31.59	72.68	2.20	3.49	39.53	56.99	73.15
1998	-2.31	3.57	39.95	38.15	90.18	2.70	3.49	39.53	59.61	74.12
1999	-2.31	4.07	47.20	44.71	107.68	3.20	3.49	39.53	62.24	75.10
2000	-2.31	4.57	54.45	51.27	125.18	3.70	3.49	39.53	64.86	76.07
2001	-2.31	5.07	61.70	57.83	142.68	4.20	3.49	39.53	67.49	77.05
2002	-2.31	5.57	68.95	62.63	158.18	4.70	3.49	39.53	69.24	77.65
2003	-2.31	6.07	76.20	65.83	171.68	5.20	3.49	39.53	70.99	78.25
2004	-2.31	6.57	83.45	69.03	183.18	5.70	3.49	39.53	72.04	78.85
2005	-2.31	7.07	90.70	72.23	192.68	6.20	3.49	39.53	73.09	79.45
2006	-2.31	7.57	96.95	73.83	200.18	6.70	3.49	39.53	74.14	80.05
2007	-2.31	8.07	102.70	75.43	205.68	7.20	3.49	39.53	75.19	80.65
2008	-2.31	8.57	107.45	75.43	209.18	7.70	3.49	39.53	76.24	81.25
2009	-2.31	9.07	112.20	75.43	210.68	8.20	3.49	39.53	77.29	81.85
2010	-2.31	9.57	115.95	75.43	212.18	8.70	3.49	39.53	78.34	82.45

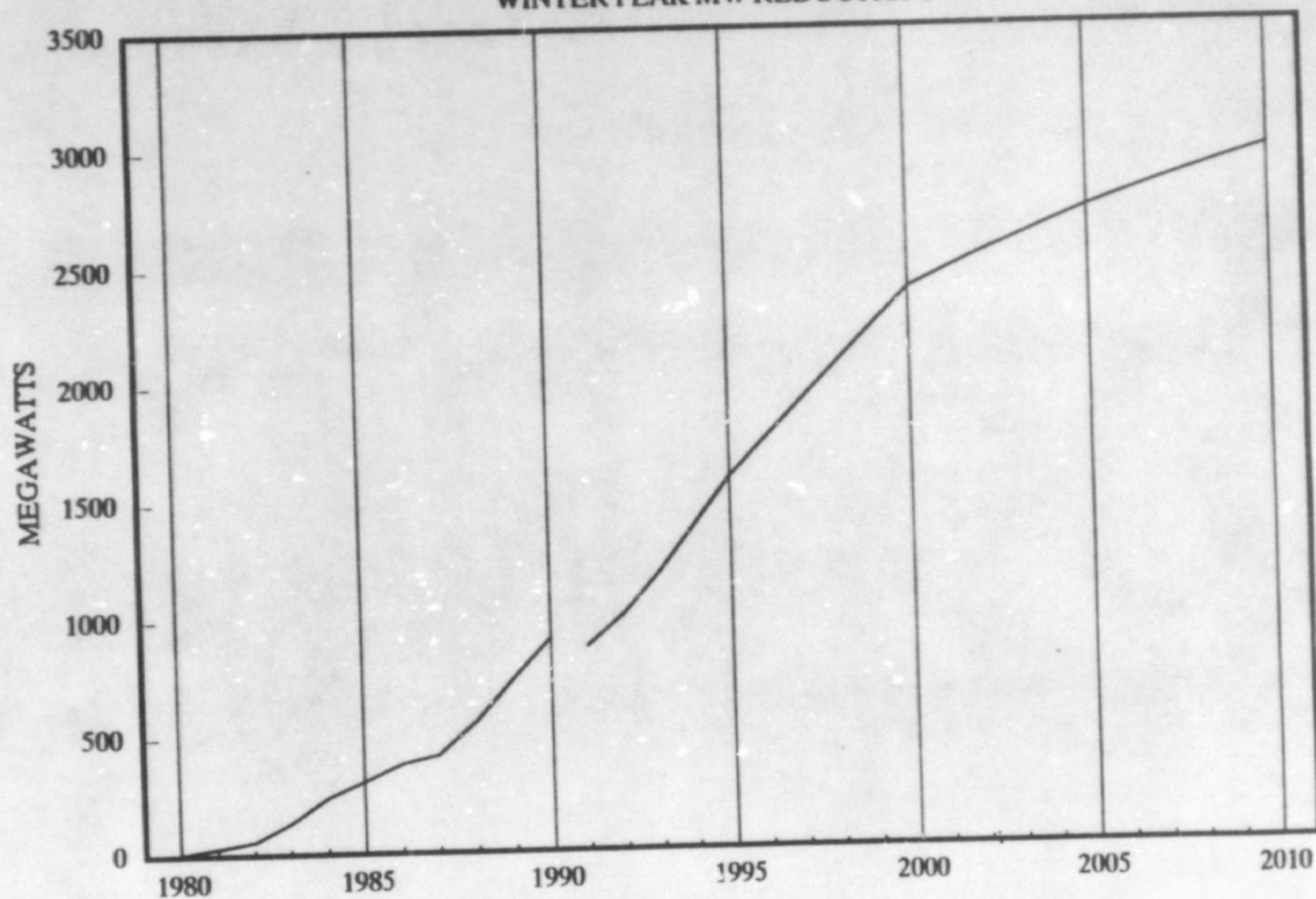
**ENERGY CONSERVATION PROGRAMS
GWH REDUCTIONS**

COMMERCIAL/INDUSTRIAL PROGRAMS (CONT'D)

YEAR	INTERIOR LIGHTING CONVERSION	A/C TUNEUP	BUSINESS ENERGY FIXUP	A/C ALLOWANCE	MOTOR REPLACE REBATE	DEMAND REDUCTION CAPITAL OFFSET	HEAT PIPE	CIRCULATION TEST AND REPAIR	STREET LIGHTING	TOTAL
HISTORY										
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.08
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.30	100.40
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.96	186.69
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.82	392.35
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.80	454.07
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.30	525.38
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.78	574.56
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	46.26	622.20
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.31	662.71
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	57.36	802.51
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	62.43	817.00
FORECAST										
1991	0.32	0.00	0.07	0.00	0.10	0.56	0.03	0.00	62.43	831.39
1992	1.22	0.10	0.17	0.50	0.25	1.68	0.13	0.25	62.43	855.83
1993	2.57	0.20	0.33	1.00	0.55	2.81	0.33	0.50	62.43	887.60
1994	4.19	0.30	0.57	1.50	0.87	4.49	0.53	0.75	62.43	933.56
1995	6.35	0.40	0.81	2.00	1.20	6.18	0.73	1.00	62.43	984.04
1996	8.69	0.50	1.05	2.50	1.55	7.86	0.93	1.25	62.43	1038.17
1997	11.03	0.60	1.29	3.00	1.90	9.55	1.13	1.50	62.43	1089.96
1998	13.37	0.70	1.53	3.50	2.25	11.23	1.33	1.75	62.43	1142.83
1999	15.71	0.80	1.77	4.00	2.60	12.92	1.53	2.00	62.43	1195.69
2000	18.05	0.90	2.01	4.50	2.95	14.60	1.73	2.25	62.43	1246.77
2001	20.39	1.00	2.25	5.00	3.30	16.29	1.93	2.50	62.43	1293.87
2002	22.73	1.10	2.49	5.50	3.60	17.97	2.13	2.75	62.43	1336.08
2003	25.07	1.20	2.73	6.00	3.85	19.66	2.23	3.00	62.43	1374.10
2004	27.41	1.30	2.97	6.50	4.00	21.34	2.33	3.25	62.43	1410.33
2005	29.75	1.40	3.21	7.00	4.10	23.03	2.33	3.50	62.43	1442.41
2006	32.09	1.50	3.45	7.50	4.10	24.71	2.33	3.75	62.43	1470.17
2007	34.43	1.60	3.69	8.00	4.10	26.40	2.33	4.00	62.43	1495.40
2008	36.77	1.70	3.93	8.50	4.10	28.08	2.33	4.25	62.43	1517.04
2009	39.11	1.80	4.17	9.00	4.10	29.76	2.33	4.50	62.43	1534.70
2010	41.45	1.90	4.41	9.50	4.10	31.45	2.33	4.75	62.43	1552.33

ENERGY CONSERVATION PROGRAM IMPACTS

WINTER PEAK MW REDUCTIONS



ENERGY CONSERVATION PROGRAMS WINTER MW REDUCTIONS

RESIDENTIAL PROGRAMS

YEAR	ENERGY MANAGEMENT			RESIDENTIAL PROGRAMS					
	COGEN	LOAD MANAGEMENT	VOLTAGE REDUCTION	ENERGY SAVER	SUPER SAVER	EDUCATION	HOME ENERGY ANALYSIS	HOME ENERGY CHECKUP	HOME ENERGY FIXUP
HISTORY									
	0.00	0.00	8.00	0.00	0.00	0.00	0.00	0.00	0.00
1980	11.00	0.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	12.00	0.00	34.00	6.82	0.00	1.80	0.63	0.25	0.00
1982	36.00	26.84	49.00	13.10	0.00	1.86	1.33	0.81	0.22
1983	42.00	93.19	63.00	23.43	4.68	1.91	1.75	1.49	0.55
1984	42.00	135.06	70.00	27.56	8.98	2.01	2.00	2.29	0.89
1985	51.00	181.09	72.00	27.56	12.08	2.09	2.13	3.18	1.11
1986	58.00	200.00	72.00	27.56	12.08	2.18	2.18	4.08	1.32
1987	61.00	328.00	77.00	27.56	12.08	2.26	2.19	4.76	1.46
1988	66.00	493.00	81.00	27.56	12.08	2.35	2.19	5.42	1.59
1989	66.00	650.00	84.00	27.56	12.08	2.43	2.22	6.82	1.95
1990									
FORECAST									
				27.56	12.08	0.00	2.22	6.89	2.02
1991	66.00	608.53	87.00	27.56	12.08	0.00	2.22	7.00	2.15
1992	66.00	703.75	89.00	27.56	12.08	0.00	2.22	7.11	2.27
1993	66.00	820.36	93.00	27.56	12.08	0.00	2.23	7.22	2.40
1994	66.00	936.96	96.00	27.56	12.08	0.00	2.23	7.33	2.52
1995	66.00	1053.57	100.00	27.56	12.08	0.00	2.23	7.45	2.65
1996	66.00	1170.18	103.00	27.56	12.08	0.00	2.23	7.56	2.78
1997	66.00	1286.78	106.00	27.56	12.08	0.00	2.23	7.67	2.90
1998	66.00	1403.39	109.00	27.56	12.08	0.00	2.23	7.78	3.03
1999	66.00	1519.99	112.00	27.56	12.08	0.00	2.24	7.89	3.15
2000	66.00	1629.37	115.00	27.56	12.08	0.00	2.24	8.00	3.28
2001	66.00	1659.22	118.00	27.56	12.08	0.00	2.24	8.11	3.37
2002	66.00	1689.07	121.00	27.56	12.08	0.00	2.24	8.22	3.44
2003	66.00	1718.92	123.00	27.56	12.08	0.00	2.24	8.33	3.51
2004	66.00	1748.77	126.00	27.56	12.08	0.00	2.24	8.44	3.59
2005	66.00	1778.62	129.00	27.56	12.08	0.00	2.25	8.56	3.63
2006	66.00	1808.47	132.00	27.56	12.08	0.00	2.25	8.67	3.68
2007	66.00	1838.32	134.00	27.56	12.08	0.00	2.25	8.78	3.72
2008	66.00	1868.17	137.00	27.56	12.08	0.00	2.25	8.89	3.77
2009	66.00	1898.02	140.00	27.56	12.08	0.00	2.25	9.00	3.81
2010	66.00	1927.87	142.00						

**ENERGY CONSERVATION PROGRAMS
WINTER MW REDUCTIONS**

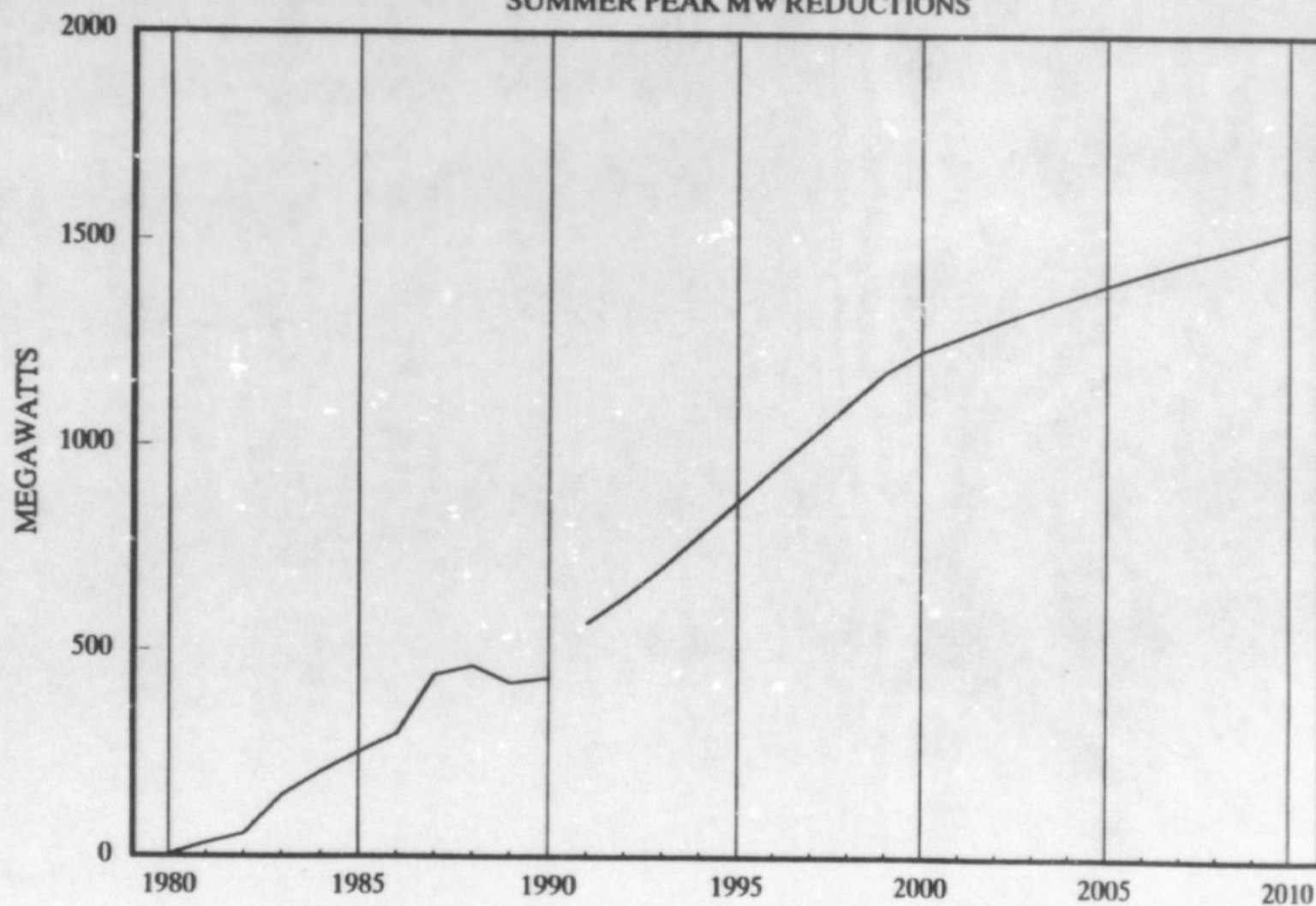
YEAR	RESIDENTIAL PROGRAMS (CONT'D)							COMMERCIAL/INDUSTRIAL PROGRAMS		
	RES. HEATWORKS	RES. COMFORT CASH LOAN	RES. A/C DUCT TEST & REPAIR	RES. INSULATION UPGRADE	RES. A/C ALLOWANCE	RES. A/C SERVICE	RES. TRADE EFFICIENCY	E.C. DESIGN AWARD	BUSINESS ENERGY CHECKUP	BUSINESS ENERGY ANALYSIS
HISTORY										
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.17
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	0.07	3.03
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.85	0.77	7.23
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.85	1.62	12.45
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.28	2.65	18.03
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.62	3.48	19.92
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.90	4.29	21.79
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.45	5.01	22.54
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.45	8.54	26.99
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00			
FORECAST										
1991	0.00	0.22	0.90	0.54	0.68	0.08	0.24	16.45	8.93	27.15
1992	29.00	0.57	2.90	1.54	3.18	0.13	0.96	16.45	9.68	27.47
1993	63.00	1.07	7.40	3.54	10.68	0.23	1.69	16.45	10.43	27.80
1994	105.00	1.57	21.90	7.59	22.18	0.39	2.41	16.45	11.18	28.12
1995	155.00	2.07	36.40	11.64	37.68	0.60	3.14	16.45	11.93	28.45
1996	155.00	2.57	50.90	15.69	55.18	0.85	3.49	16.45	12.68	28.77
1997	155.00	3.07	65.40	19.74	72.68	1.10	3.49	16.45	13.43	29.10
1998	155.00	3.57	79.90	23.84	90.18	1.35	3.49	16.45	14.18	29.42
1999	155.00	4.07	94.40	27.94	107.68	1.60	3.49	16.45	14.93	29.75
2000	155.00	4.57	108.90	32.04	125.18	1.85	3.49	16.45	15.68	30.07
2001	155.00	5.07	123.40	36.14	142.68	2.10	3.49	16.45	16.43	30.40
2002	155.00	5.57	137.90	39.14	158.18	2.35	3.49	16.45	16.93	30.60
2003	155.00	6.07	152.40	41.14	171.68	2.60	3.49	16.45	17.43	30.80
2004	155.00	6.57	166.90	43.14	183.18	2.85	3.49	16.45	17.73	31.00
2005	155.00	7.07	181.40	45.14	192.68	3.10	3.49	16.45	18.03	31.20
2006	155.00	7.57	193.90	46.14	200.18	3.35	3.49	16.45	18.33	31.40
2007	155.00	8.07	205.40	47.14	205.68	3.60	3.49	16.45	18.63	31.60
2008	155.00	8.57	214.90	47.14	209.18	3.85	3.49	16.45	18.93	31.80
2009	155.00	9.07	224.40	47.14	210.68	4.10	3.49	16.45	19.23	32.00
2010	155.00	9.57	231.90	47.14	212.18	4.35	3.49	16.45	19.53	32.20

**ENERGY CONSERVATION PROGRAMS
WINTER MW REDUCTIONS**

YEAR	COMMERCIAL/INDUSTRIAL PROGRAMS (CONT'D)								STREET LIGHTING	TOTAL
	INTERIOR LIGHTING CONVERSION	A/C TUNEUP	BUSINESS ENERGY FIXUP	A/C ALLOWANCE	MOTOR REPLACE REBATE	DEMAND REDUCTION CAPITAL OFFSET	HEAT PIPE	CIRCULATION TEST AND REPAIR		
HISTORY										
									0.00	6.00
									0.00	31.00
									0.00	55.69
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	133.48
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	239.17
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	307.41
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	379.10
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	414.42
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	556.29
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	735.19
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	905.04
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
FORECAST										
									0.00	867.69
									0.00	1003.40
									0.00	1176.42
1991	0.11	0.00	0.03	0.00	0.04	0.05	0.00	0.00	0.00	1372.71
1992	0.41	0.05	0.06	0.50	0.10	0.14	0.00	0.50	0.00	1582.25
1993	0.86	0.10	0.12	1.00	0.22	0.23	0.00	1.00	0.00	1742.52
1994	0.86	0.10	0.12	1.50	0.35	0.36	0.00	1.50	0.00	1902.42
1995	1.40	0.15	0.21	2.00	0.48	0.50	0.00	2.50	0.00	2062.39
1996	2.12	0.20	0.30	2.50	0.62	0.63	0.00	3.00	0.00	2222.35
1997	2.90	0.25	0.39	3.00	0.76	0.77	0.00	3.50	0.00	2375.09
1998	3.68	0.30	0.48	3.50	0.90	0.90	0.00	4.00	0.00	2448.30
1999	4.46	0.35	0.57	4.00	1.04	1.04	0.00	4.50	0.00	2517.98
2000	5.24	0.40	0.66	4.50	1.18	1.17	0.00	5.00	0.00	2583.62
2001	6.02	0.45	0.75	5.00	1.32	1.31	0.00	5.50	0.00	2648.01
2002	6.80	0.50	0.84	5.50	1.44	1.44	0.00	6.00	0.00	2710.39
2003	7.58	0.55	0.93	6.00	1.54	1.58	0.00	6.50	0.00	2767.71
2004	8.36	0.60	1.02	6.50	1.60	1.71	0.00	7.00	0.00	2821.02
2005	9.14	0.65	1.11	7.00	1.64	1.85	0.00	7.50	0.00	2870.33
2006	9.92	0.70	1.20	7.50	1.64	1.98	0.00	8.00	0.00	2917.64
2007	10.70	0.75	1.29	8.00	1.64	2.12	0.00	8.50	0.00	2961.96
2008	11.48	0.80	1.38	8.50	1.64	2.25	0.00	9.00	0.00	
2009	12.26	0.85	1.47	9.00	1.64	2.39	0.00	9.50	0.00	
2010	13.04	0.90	1.56	9.50	1.64	2.52	0.00			
	13.82	0.95	1.65							

ENERGY CONSERVATION PROGRAM IMPACTS

SUMMER PEAK MW REDUCTIONS



**ENERGY CONSERVATION PROGRAMS
SUMMER MW REDUCTIONS**

YEAR	ENERGY MANAGEMENT			RESIDENTIAL PROGRAMS					
	COGEN	LOAD MANAGEMENT	VOLTAGE REDUCTION	ENERGY SAVER	SUPER SAVER	EDUCATION	HOME ENERGY ANALYSIS	HOME ENERGY CHECKUP	HOME ENERGY FIXUP
HISTORY									
1980	0.00	0.00	4.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	11.00	0.00	14.00	4.60	0.00	1.44	0.47	0.12	0.00
1982	14.00	0.65	24.00	8.85	0.00	1.49	1.00	0.41	0.18
1983	41.00	40.13	35.00	15.82	0.00	1.53	1.31	0.74	0.47
1984	42.00	71.86	44.00	18.61	3.05	1.61	1.50	1.15	0.75
1985	43.00	96.56	53.00	18.61	5.85	1.68	1.60	1.59	0.94
1986	58.00	116.02	55.00	18.61	7.87	1.74	1.63	2.04	1.12
1987	58.00	250.00	60.00	18.61	7.87	1.81	1.64	2.38	1.24
1988	61.00	258.29	65.00	18.61	7.87	1.88	1.65	2.71	1.35
1989	66.00	207.00	67.00	18.61	7.87	1.94	1.68	3.01	1.46
1990	66.00	212.00	70.00	18.61	7.87	0.00	1.66	3.41	1.65
FORECAST									
1991	66.00	341.62	73.00	18.61	7.87	0.00	1.66	3.48	1.72
1992	66.00	396.86	75.00	18.61	7.87	0.00	1.66	3.59	1.85
1993	66.00	456.06	77.00	18.61	7.87	0.00	1.66	3.70	1.97
1994	66.00	515.25	80.00	18.61	7.87	0.00	1.67	3.81	2.10
1995	66.00	574.44	83.00	18.61	7.87	0.00	1.67	3.92	2.22
1996	66.00	633.63	86.00	18.61	7.87	0.00	1.67	4.04	2.35
1997	66.00	692.82	88.00	18.61	7.87	0.00	1.67	4.15	2.48
1998	66.00	752.02	91.00	18.61	7.87	0.00	1.67	4.26	2.60
1999	66.00	811.21	93.00	18.61	7.87	0.00	1.67	4.37	2.73
2000	66.00	841.04	95.00	18.61	7.87	0.00	1.67	4.48	2.85
2001	66.00	856.20	97.00	18.61	7.87	0.00	1.68	4.59	2.98
2002	66.00	871.36	100.00	18.61	7.87	0.00	1.68	4.70	3.07
2003	66.00	886.52	102.00	18.61	7.87	0.00	1.68	4.81	3.14
2004	66.00	901.68	104.00	18.61	7.87	0.00	1.68	4.92	3.21
2005	66.00	916.84	106.00	18.61	7.87	0.00	1.68	5.03	3.29
2006	66.00	932.00	108.00	18.61	7.87	0.00	1.68	5.15	3.33
2007	66.00	947.16	110.00	18.61	7.87	0.00	1.69	5.26	3.38
2008	66.00	962.31	112.00	18.61	7.87	0.00	1.69	5.37	3.42
2009	66.00	977.47	114.00	18.61	7.87	0.00	1.69	5.48	3.47
2010	66.00	992.63	116.00	18.61	7.87	0.00	1.69	5.59	3.51

**ENERGY CONSERVATION PROGRAMS
SUMMER MW REDUCTIONS**

YEAR	RESIDENTIAL PROGRAMS (CONT'D)							COMMERCIAL/INDUSTRIAL PROGRAMS		
	RES. HEATWORKS	RES. COMFORT CASH LOAN	RES. A/C DUCT TEST & REPAIR	RES. INSULATION UPGRADE	RES. A/C ALLOWANCE	RES. A/C SERVICE	RES. TRADE EFFICIENCY	E.C. DESIGN AWARD	BUSINESS ENERGY CHECKUP	BUSINESS ENERGY ANALYSIS
HISTORY										
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.17
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.18	0.07	3.03
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.70	0.77	7.23
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.58	1.62	12.45
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.93	2.65	18.03
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.18	3.48	19.92
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.36	4.29	21.79
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.81	5.01	22.54
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.81	6.06	24.54
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.81	8.54	26.99
FORECAST										
1991	0.00	0.11	0.45	0.27	0.17	0.06	0.09	15.81	8.93	27.15
1992	1.00	0.29	1.45	0.77	0.80	0.13	0.38	15.81	9.68	27.47
1993	3.00	0.54	3.70	1.77	2.67	0.23	0.67	15.81	10.43	27.80
1994	4.00	0.79	10.95	3.60	5.55	0.39	0.96	15.81	11.18	28.12
1995	6.00	1.04	18.20	5.82	9.42	0.60	1.25	15.81	11.93	28.45
1996	6.00	1.29	25.45	7.85	13.80	0.85	1.39	15.81	12.68	28.77
1997	6.00	1.54	32.70	9.87	18.17	1.10	1.39	15.81	13.43	29.10
1998	6.00	1.79	39.95	11.92	22.55	1.35	1.39	15.81	14.18	29.42
1999	6.00	2.04	47.20	13.97	26.92	1.60	1.39	15.81	14.93	29.75
2000	6.00	2.29	54.45	16.02	31.30	1.85	1.39	15.81	15.68	30.07
2001	6.00	2.54	61.70	18.07	35.67	2.10	1.39	15.81	16.43	30.40
2002	6.00	2.79	68.95	19.57	39.55	2.35	1.39	15.81	16.93	30.60
2003	6.00	3.04	76.20	20.57	42.92	2.60	1.39	15.81	17.43	30.80
2004	6.00	3.29	83.45	21.57	45.80	2.85	1.39	15.81	17.73	31.00
2005	6.00	3.54	90.70	22.57	48.17	3.10	1.39	15.81	18.03	31.20
2006	6.00	3.79	96.95	23.07	50.05	3.35	1.39	15.81	18.33	31.40
2007	6.00	4.04	102.70	23.57	51.42	3.60	1.39	15.81	18.63	31.60
2008	6.00	4.29	107.45	23.57	52.30	3.85	1.39	15.81	18.93	31.80
2009	6.00	4.54	112.20	23.57	52.67	4.10	1.39	15.81	19.23	32.00
2010	6.00	4.79	115.95	23.57	53.05	4.35	1.39	15.81	19.53	32.20

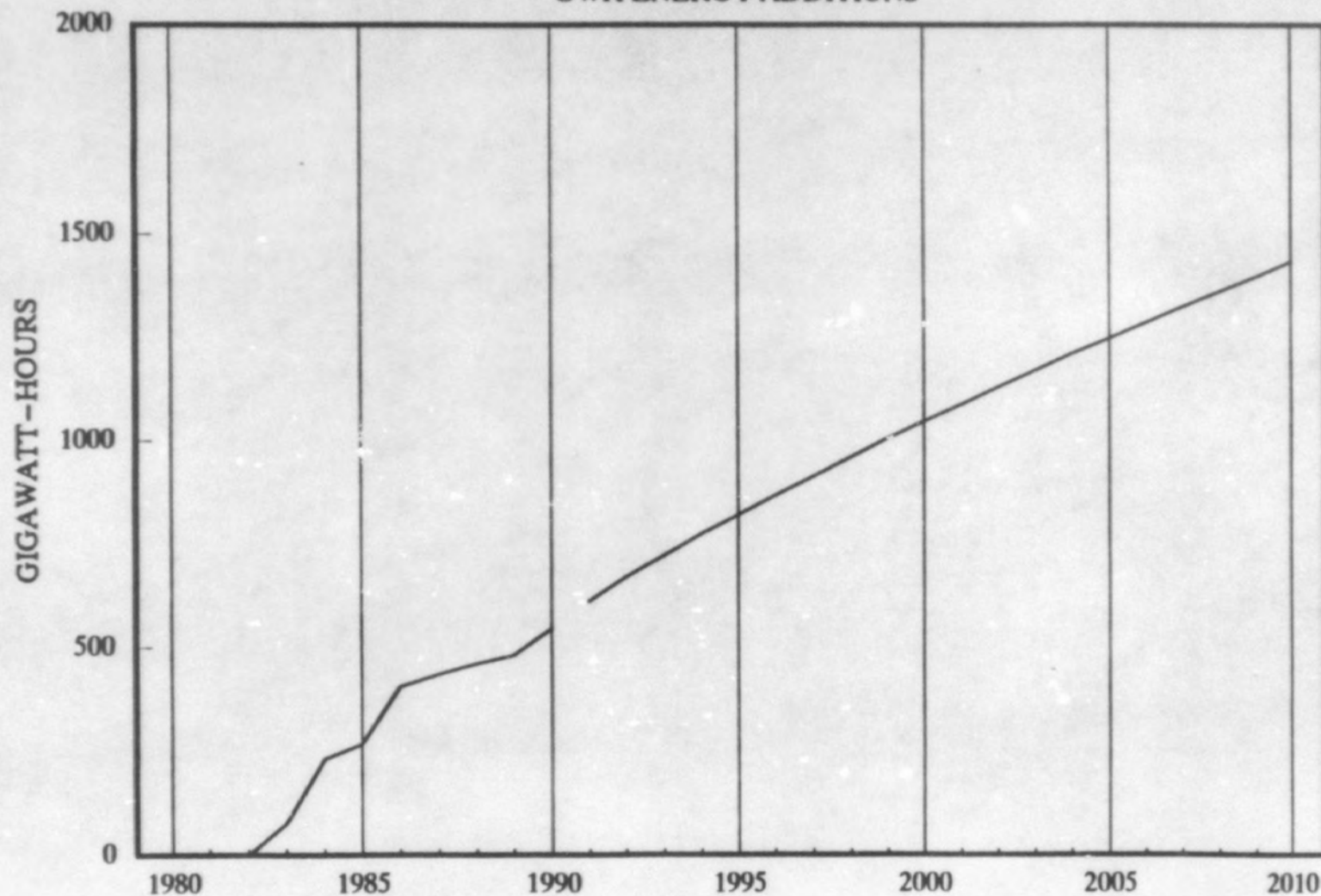
**ENERGY CONSERVATION PROGRAMS
SUMMER MW REDUCTIONS**

COMMERCIAL/INDUSTRIAL PROGRAMS (CONT'D)

YEAR	INTERIOR LIGHTING CONVERSION	A/C TUNEUP	BUSINESS ENERGY FDUP	A/C ALLOWANCE	MOTOR REPLACE REBATE	DEMAND REDUCTION CAPITAL OFFSET	HEAT PIPE	CIRCULATION TEST AND REPAIR	STREET LIGHTING	TOTAL
HISTORY										
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.82
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	54.86
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	147.70
1984	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	205.18
1985	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	252.44
1986	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	296.61
1987	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	440.99
1988	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	461.52
1989	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	420.98
1990	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	432.54
FORECAST										
1991	0.11	0.00	0.03	0.00	0.04	0.18	0.03	0.00	0.00	567.38
1992	0.41	0.05	0.06	0.13	0.10	0.54	0.13	0.25	0.00	630.88
1993	0.86	0.10	0.12	0.25	0.22	0.90	0.33	0.50	0.00	702.77
1994	1.40	0.15	0.21	0.38	0.35	1.44	0.53	0.75	0.00	782.05
1995	2.12	0.20	0.30	0.50	0.48	1.98	0.73	1.00	0.00	863.56
1996	2.90	0.25	0.39	0.63	0.62	2.52	0.93	1.25	0.00	943.53
1997	3.68	0.30	0.48	0.75	0.76	3.06	1.13	1.50	0.00	1022.36
1998	4.46	0.35	0.57	0.86	0.90	3.60	1.33	1.75	0.00	1102.22
1999	5.24	0.40	0.66	1.00	1.04	4.14	1.53	2.00	0.00	1181.07
2000	6.02	0.45	0.75	1.13	1.18	4.68	1.73	2.25	0.00	1230.57
2001	6.80	0.50	0.84	1.25	1.22	5.22	1.93	2.50	0.00	1265.39
2002	7.58	0.55	0.93	1.38	1.44	5.76	2.13	2.75	0.00	1299.73
2003	8.36	0.60	1.02	1.50	1.54	6.30	2.23	3.00	0.00	1331.94
2004	9.14	0.65	1.11	1.63	1.60	6.84	2.33	3.25	0.00	1363.40
2005	9.92	0.70	1.20	1.75	1.64	7.38	2.33	3.50	0.00	1394.25
2006	10.70	0.75	1.29	1.88	1.64	7.92	2.33	3.75	0.00	1423.02
2007	11.48	0.80	1.38	2.00	1.64	8.46	2.33	4.00	0.00	1450.80
2008	12.26	0.85	1.47	2.13	1.64	9.00	2.33	4.25	0.00	1476.57
2009	13.04	0.90	1.56	2.25	1.64	9.54	2.33	4.50	0.00	1501.85
2010	13.82	0.95	1.65	2.38	1.64	10.08	2.33	4.75	0.00	1526.12

MARKETING PROGRAM IMPACTS

GWH ENERGY ADDITIONS

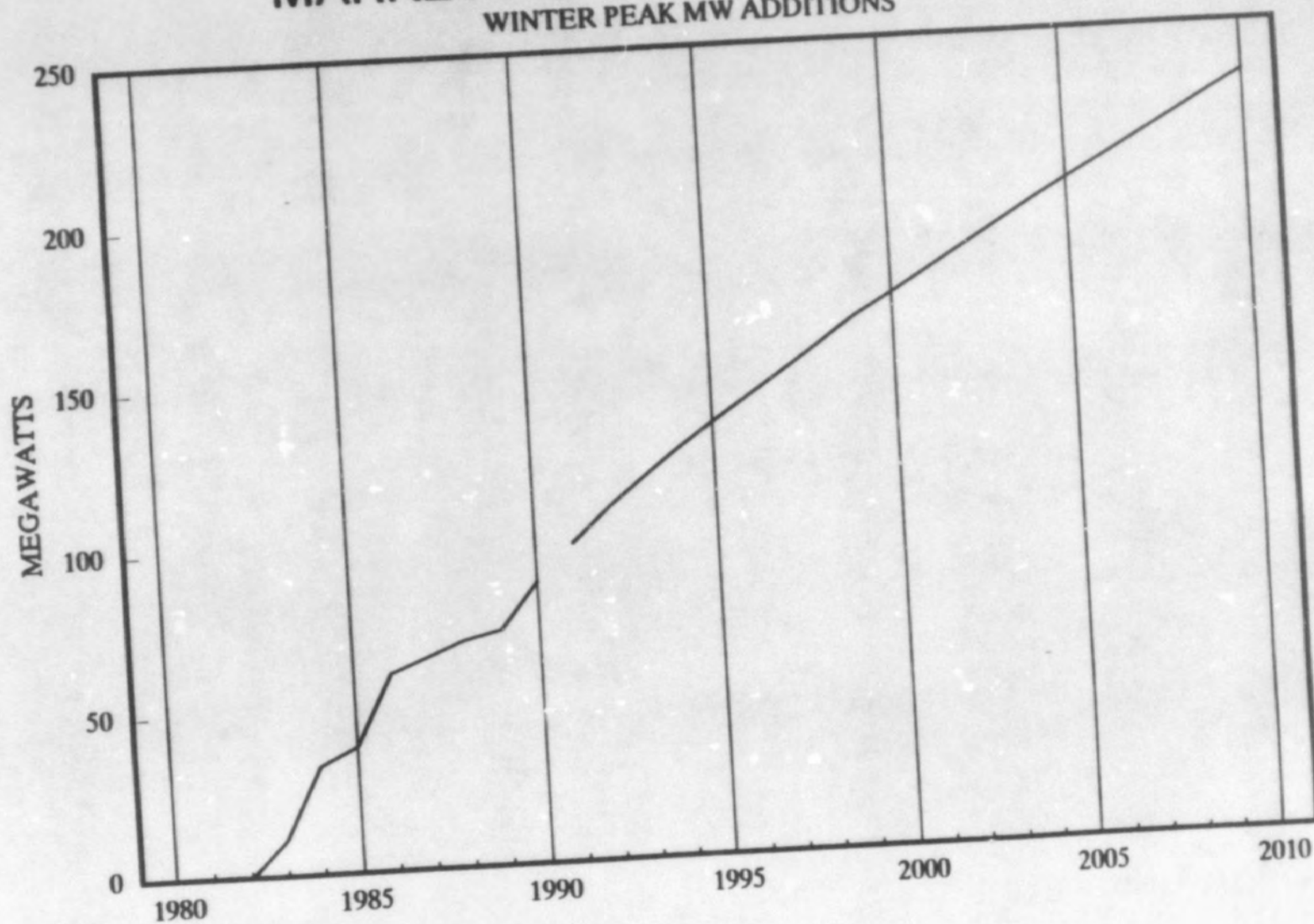


**MARKETING PROGRAMS
GWH INCREASES**

YEAR	AVERAGE BILLING PLAN	RESIDENTIAL LIGHTING	COM/IND HEAT PUMP WATER HEATER	COM/IND LIGHTING	COM/IND LIGHTING LEASE	COM/IND ELECTRIC MATERIALS	COM ECONOMIC DEVELOPMENT	IND ECONOMIC DEVELOPMENT	TOTAL
HISTORY									
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1982	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1983	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1984	0.00	0.00	0.00	0.00	0.00	0.00	47.90	28.00	75.90
1985	3.43	0.10	0.00	0.00	0.00	0.00	47.90	182.20	230.10
1986	2.92	0.65	0.43	1.14	0.00	0.39	51.70	210.60	266.03
1987	5.54	1.34	0.47	3.14	0.00	0.42	74.00	324.80	404.33
1988	6.87	1.76	0.51	4.45	6.48	0.42	79.00	343.50	433.41
1989	10.46	1.96	0.59	5.01	9.95	0.42	90.10	348.60	459.21
1990	14.66	1.96	0.59	5.01	9.95	0.42	100.80	349.60	476.79
							117.9	394.50	544.99
FORECAST									
1991	17.66	1.96	0.59	5.01	9.95	0.42	132.0	442.00	609.59
1992	19.46	1.96	0.59	5.01	9.95	0.42	145.2	486.20	668.79
1993	20.36	1.96	0.59	5.01	9.95	0.42	157.0	525.40	720.69
1994	20.96	1.96	0.59	5.01	9.95	0.42	168.7	564.70	772.29
1995	21.56	1.96	0.59	5.01	9.95	0.42	179.1	599.80	818.39
1996	22.16	1.96	0.59	5.01	9.95	0.42	189.6	634.80	864.49
1997	22.76	1.96	0.59	5.01	9.95	0.42	200.1	669.80	910.59
1998	23.36	1.96	0.59	5.01	9.95	0.42	210.5	704.90	956.69
1999	23.96	1.96	0.59	5.01	9.95	0.42	221.0	739.90	1002.79
2000	24.56	1.96	0.59	5.01	9.95	0.42	230.2	770.70	1043.39
2001	25.16	1.96	0.59	5.01	9.95	0.42	239.4	801.50	1083.99
2002	25.76	1.96	0.59	5.01	9.95	0.42	248.6	832.30	1124.59
2003	26.36	1.96	0.59	5.01	9.95	0.42	257.8	863.10	1165.19
2004	26.96	1.96	0.59	5.01	9.95	0.42	267.0	893.90	1205.79
2005	27.56	1.96	0.59	5.01	9.95	0.42	275.5	922.40	1243.39
2006	28.16	1.96	0.59	5.01	9.95	0.42	284.0	950.90	1280.99
2007	28.76	1.96	0.59	5.01	9.95	0.42	292.5	979.40	1318.59
2008	29.36	1.96	0.59	5.01	9.95	0.42	301.0	1007.90	1356.19
2009	29.96	1.96	0.59	5.01	9.95	0.42	309.6	1036.30	1393.79
2010	30.56	1.96	0.59	5.01	9.95	0.42	317.8	1064.10	1430.39

MARKETING PROGRAM IMPACTS

WINTER PEAK MW ADDITIONS

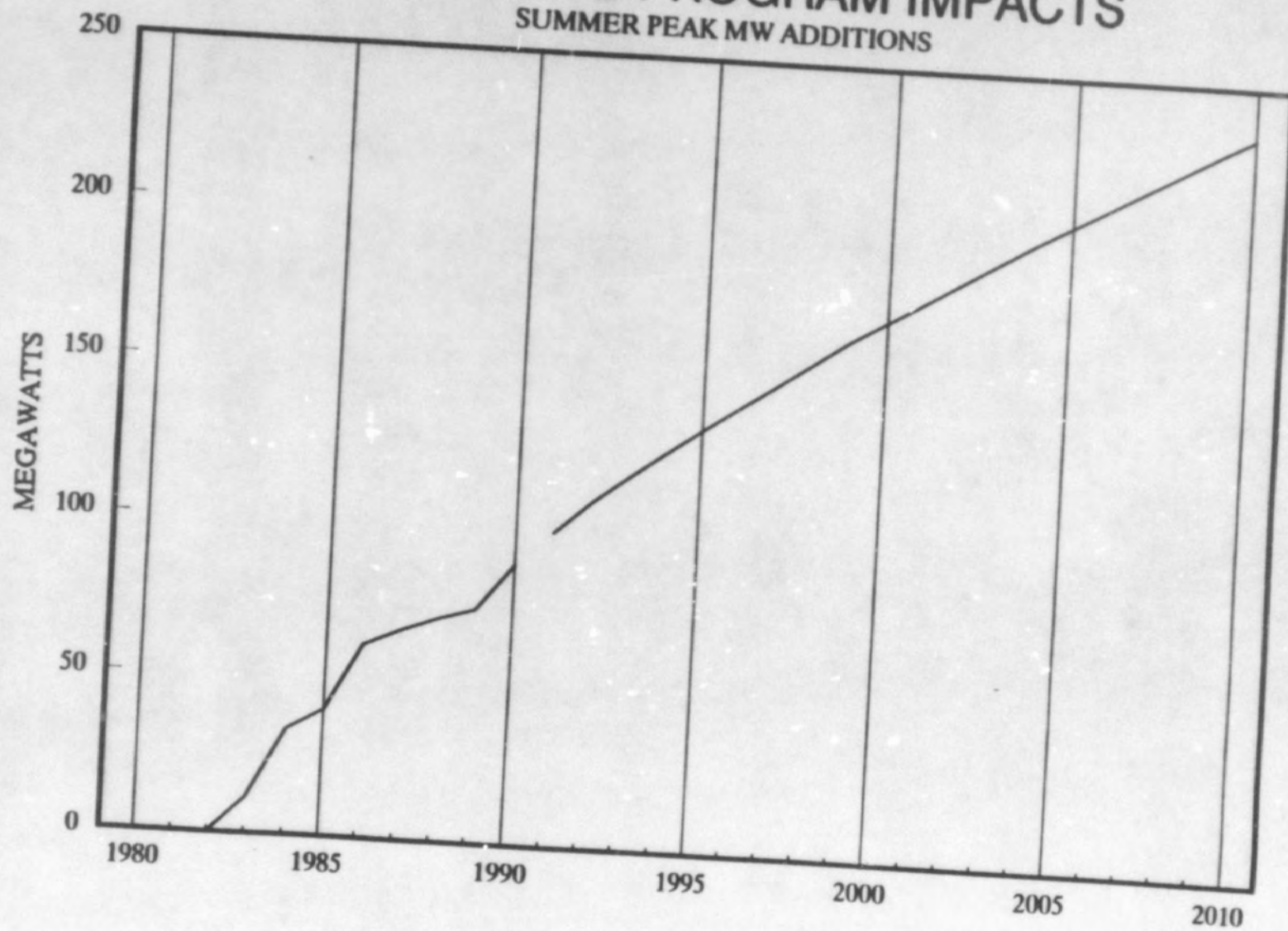


MARKETING PROGRAMS
WINTER MW INCREASES

YEAR	AVERAGE BILLING PLAN	RESIDENTIAL LIGHTING	COM/IND HEAT PUMP WATER HEATER	COM/IND LIGHTING	COM/IND LIGHTING LEASE	COM/IND ELECTRIC MATERIALS	COM ECONOMIC DEVELOPMENT	IND ECONOMIC DEVELOPMENT	TOTAL
HISTORY									
1980	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1981	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1982	0.00	0.00	0.00	0.00	0.00	0.00	6.30	4.90	11.20
1983	0.00	0.00	0.00	0.00	0.00	0.00	6.30	27.00	33.30
1984	0.00	0.00	0.00	0.00	0.00	0.00	7.00	31.70	38.70
1985	0.00	0.00	0.00	0.00	0.00	0.00	10.30	49.40	60.68
1986	0.98	0.00	0.00	0.00	0.00	0.24	11.20	52.80	65.19
1987	0.84	0.00	0.11	0.00	0.00	0.26	13.50	54.40	69.87
1988	1.59	0.00	0.12	0.00	0.00	0.26	15.50	54.70	72.56
1989	1.97	0.00	0.13	0.00	0.00	0.26	19.20	64.30	86.91
1990	3.00	0.00	0.15	0.00	0.00	0.26			
FORECAST									
1991	4.20	0.00	0.15	0.00	0.00	0.26	21.50	72.10	98.21
1992	5.06	0.00	0.15	0.00	0.00	0.26	23.70	79.30	108.47
1993	5.58	0.00	0.15	0.00	0.00	0.26	25.60	85.70	117.29
1994	5.84	0.00	0.15	0.00	0.00	0.26	27.50	92.10	125.85
1995	6.01	0.00	0.15	0.00	0.00	0.26	29.20	97.80	133.42
1996	6.18	0.00	0.15	0.00	0.00	0.26	30.90	103.50	140.99
1997	6.35	0.00	0.15	0.00	0.00	0.26	32.60	109.20	148.56
1998	6.52	0.00	0.15	0.00	0.00	0.26	34.30	114.90	156.13
1999	6.70	0.00	0.15	0.00	0.00	0.26	36.00	120.70	163.81
2000	6.87	0.00	0.15	0.00	0.00	0.26	37.50	125.70	170.48
2001	7.04	0.00	0.15	0.00	0.00	0.26	39.00	130.70	177.15
2002	7.21	0.00	0.15	0.00	0.00	0.26	40.50	135.70	183.82
2003	7.38	0.00	0.15	0.00	0.00	0.26	42.00	140.80	190.59
2004	7.56	0.00	0.15	0.00	0.00	0.26	43.50	145.80	197.27
2005	7.73	0.00	0.15	0.00	0.00	0.26	44.90	150.40	203.44
2006	7.90	0.00	0.15	0.00	0.00	0.26	46.30	155.10	209.71
2007	8.07	0.00	0.15	0.00	0.00	0.26	47.70	159.70	215.88
2008	8.24	0.00	0.15	0.00	0.00	0.26	49.10	164.40	222.15
2009	8.42	0.00	0.15	0.00	0.00	0.26	50.50	169.00	228.33
2010	8.59	0.00	0.15	0.00	0.00	0.26	51.80	173.50	234.30

MARKETING PROGRAM IMPACTS

SUMMER PEAK MW ADDITIONS



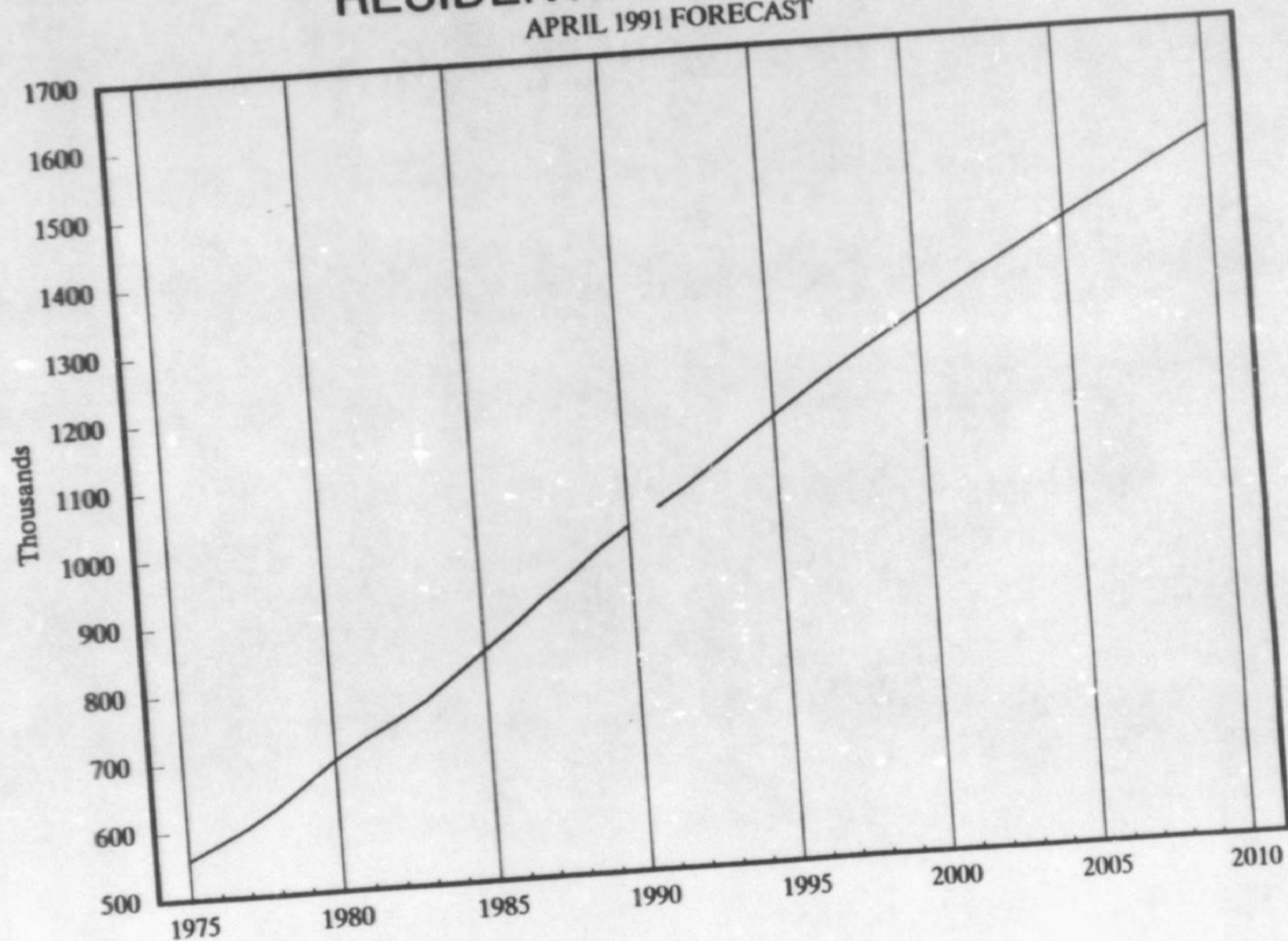
MARKETING PROGRAMS SUMMER MW INCREASES

YEAR	AVERAGE BILLING PLAN	RESIDENTIAL LIGHTING	COM/IND HEAT PUMP WATER HEATER	COM/IND LIGHTING	COM/IND LIGHTING LEASE	COM/IND ELECTRIC MATERIALS	COM ECONOMIC DEVELOPMENT	IND ECONOMIC DEVELOPMENT	TOTAL
									0.00
								0.00	0.00
							0.00	0.00	0.00
					0.00	0.00	0.00	0.00	11.20
			0.00	0.00	0.00	0.00	6.30	4.90	33.30
HISTORY			0.00	0.00	0.00	0.00	6.30	27.00	39.68
1980	0.00	0.00	0.00	0.00	0.00	0.00	7.00	31.70	60.89
1981	0.00	0.00	0.00	0.00	0.00	0.00	7.00	49.40	65.97
1982	0.00	0.00	0.00	0.00	0.00	0.24	11.20	54.40	70.26
1983	0.00	0.00	0.00	0.00	0.00	0.26	13.50	54.70	73.61
1984	0.28	0.00	0.11	0.00	0.00	0.26	15.50	64.30	88.11
1985	0.84	0.00	0.12	0.00	0.00	0.26	19.20		
1986	1.59	0.00	0.13	0.00	0.00				
1987	1.97	0.00	0.15	0.00	0.00				
1988	3.00	0.00	0.15						
1989	4.20	0.00							
1990									99.07
								72.10	108.99
							21.50	79.30	117.55
						0.26	23.70	85.70	126.02
					0.00	0.26	25.60	92.10	133.59
			0.15	0.00	0.00	0.26	27.50	97.80	141.16
FORECAST			0.15	0.00	0.00	0.26	29.20	103.50	148.73
1991	5.06	0.00	0.15	0.00	0.00	0.26	30.90	109.20	156.31
1992	5.58	0.00	0.15	0.00	0.00	0.26	32.60	114.90	163.98
1993	5.84	0.00	0.15	0.00	0.00	0.26	34.30	120.70	170.65
1994	6.01	0.00	0.15	0.00	0.00	0.26	36.00	125.70	177.32
1995	6.18	0.00	0.15	0.00	0.00	0.26	37.50	130.70	183.99
1996	6.35	0.00	0.15	0.00	0.00	0.26	39.00	135.70	190.77
1997	6.52	0.00	0.15	0.00	0.00	0.26	40.50	140.80	197.44
1998	6.70	0.00	0.15	0.00	0.00	0.26	42.00	145.80	203.61
1999	6.87	0.00	0.15	0.00	0.00	0.26	43.50	150.40	209.88
2000	7.04	0.00	0.15	0.00	0.00	0.26	44.90	155.10	216.05
2001	7.21	0.00	0.15	0.00	0.00	0.26	46.30	159.70	222.33
2002	7.38	0.00	0.15	0.00	0.00	0.26	47.70	164.40	228.50
2003	7.56	0.00	0.15	0.00	0.00	0.26	49.10	169.00	234.47
2004	7.73	0.00	0.15	0.00	0.00	0.26	50.50	173.50	
2005	7.90	0.00	0.15	0.00	0.00	0.26	51.80		
2006	8.07	0.00	0.15	0.00	0.00				
2007	8.24	0.00	0.15	0.00	0.00				
2008	8.42	0.00	0.15	0.00	0.00				
2009	8.59	0.00	0.15	0.00	0.00				
2010	8.76	0.00	0.15	0.00	0.00				

CUSTOMER FORECAST

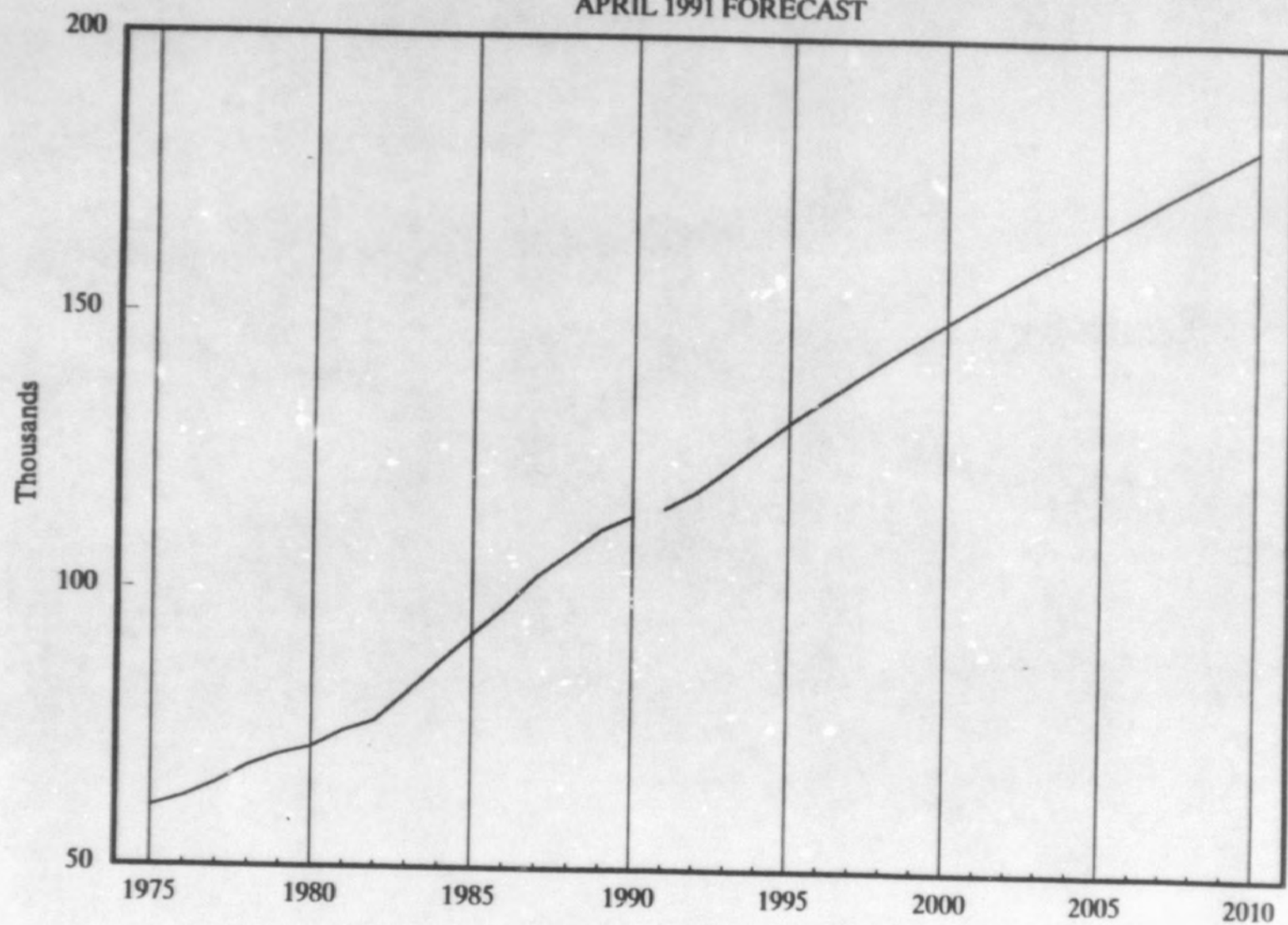
RESIDENTIAL CUSTOMERS

APRIL 1991 FORECAST



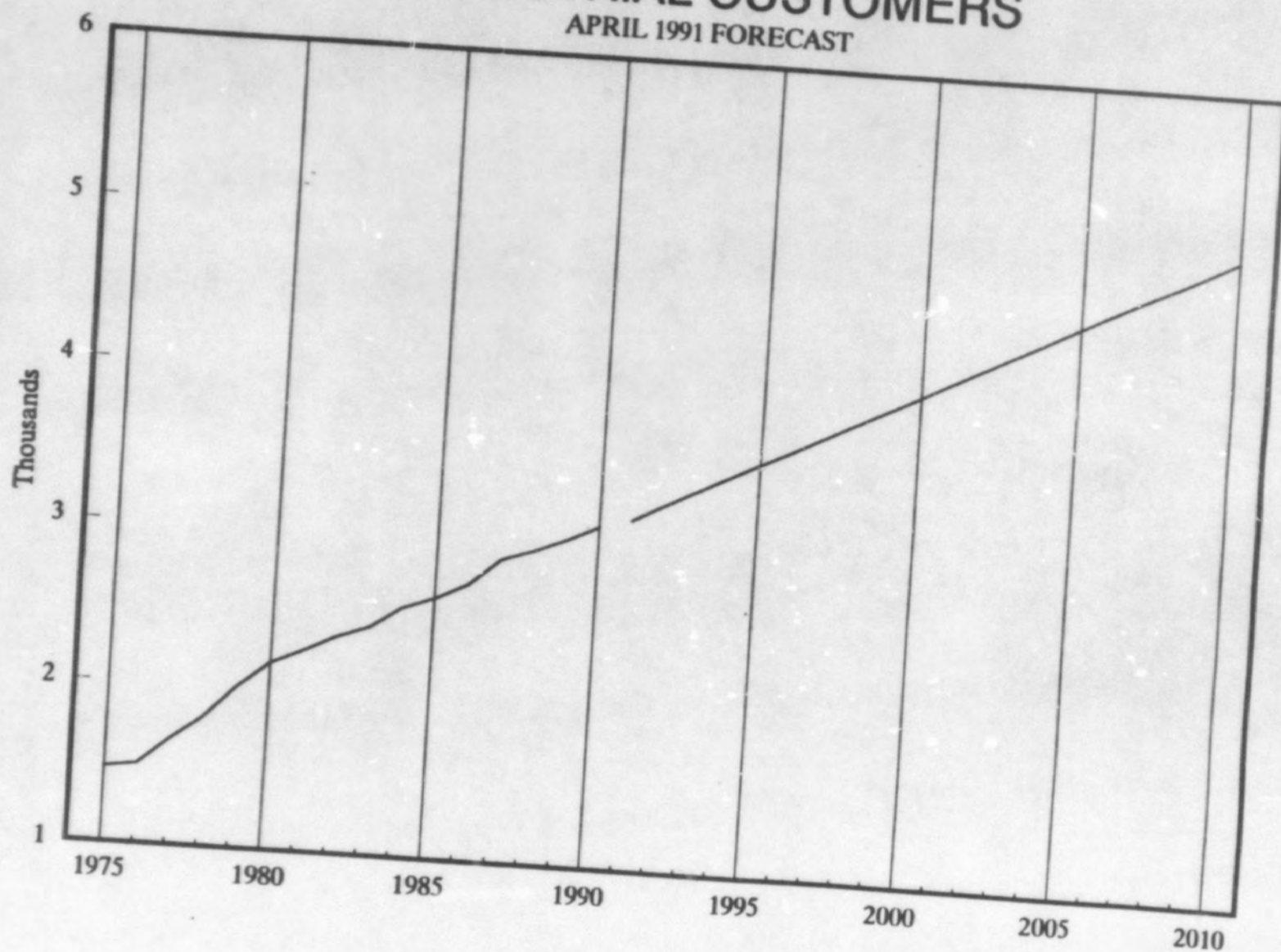
COMMERCIAL CUSTOMERS

APRIL 1991 FORECAST



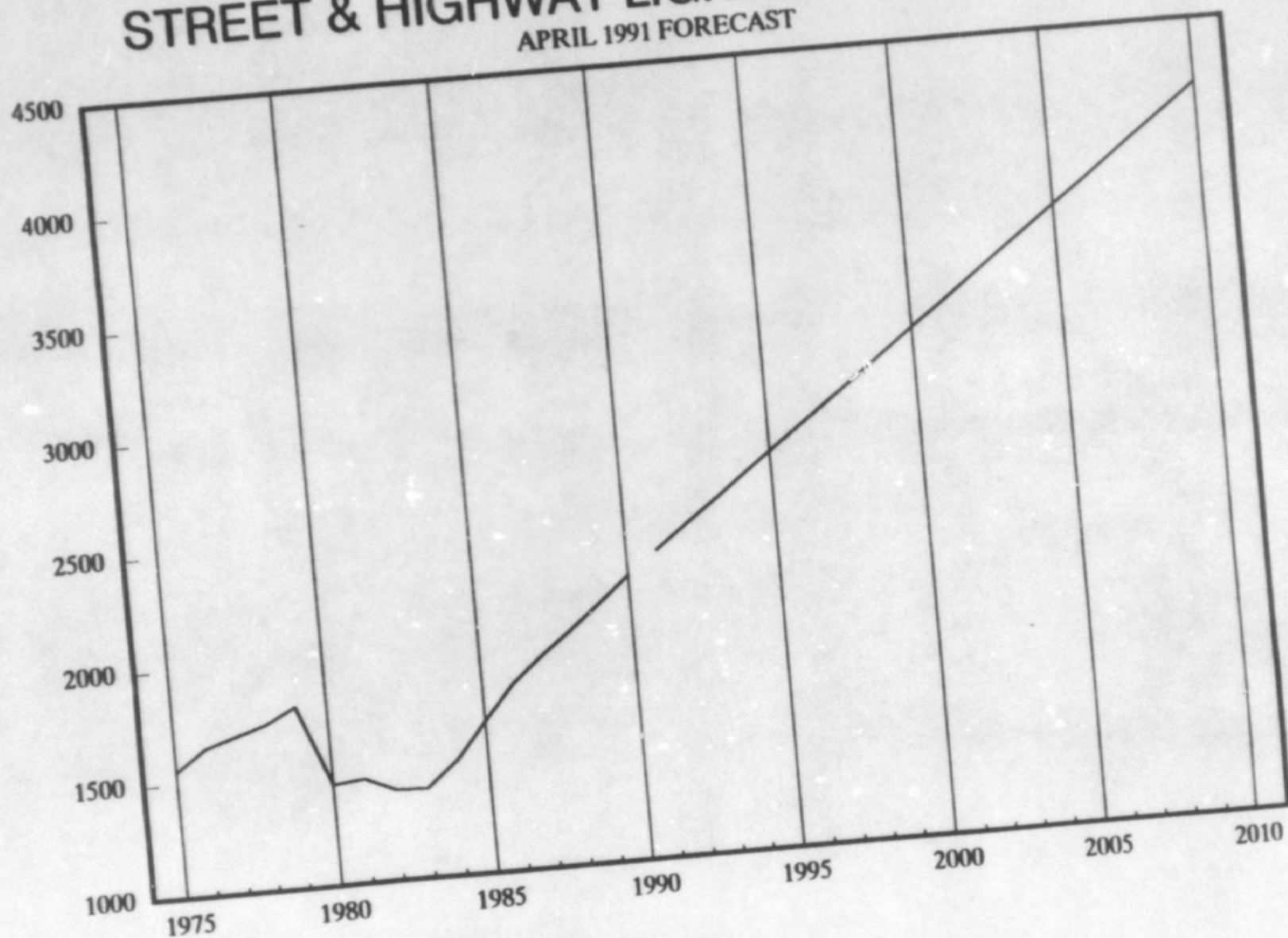
INDUSTRIAL CUSTOMERS

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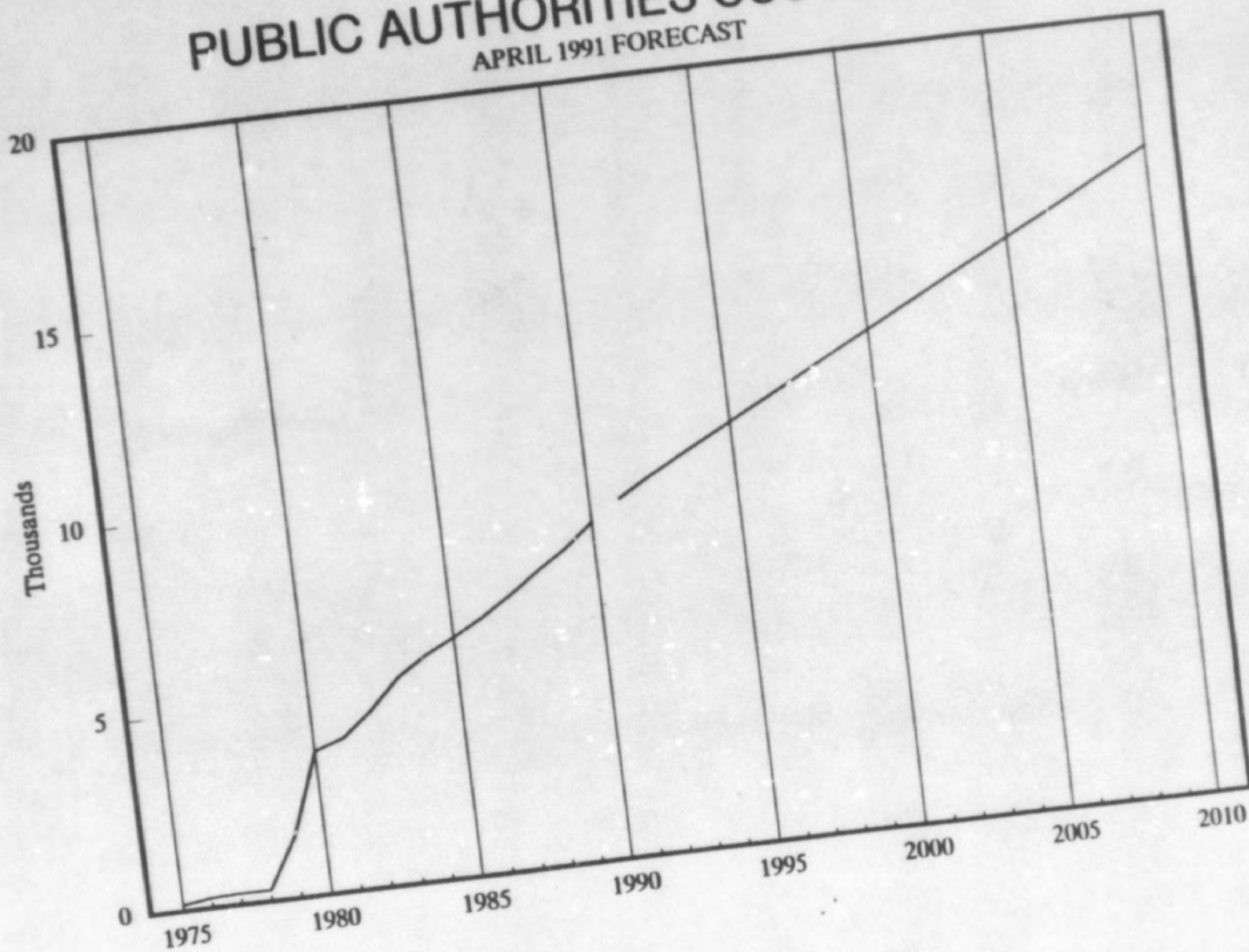
STREET & HIGHWAY LIGHTING CUSTOMERS

APRIL 1991 FORECAST



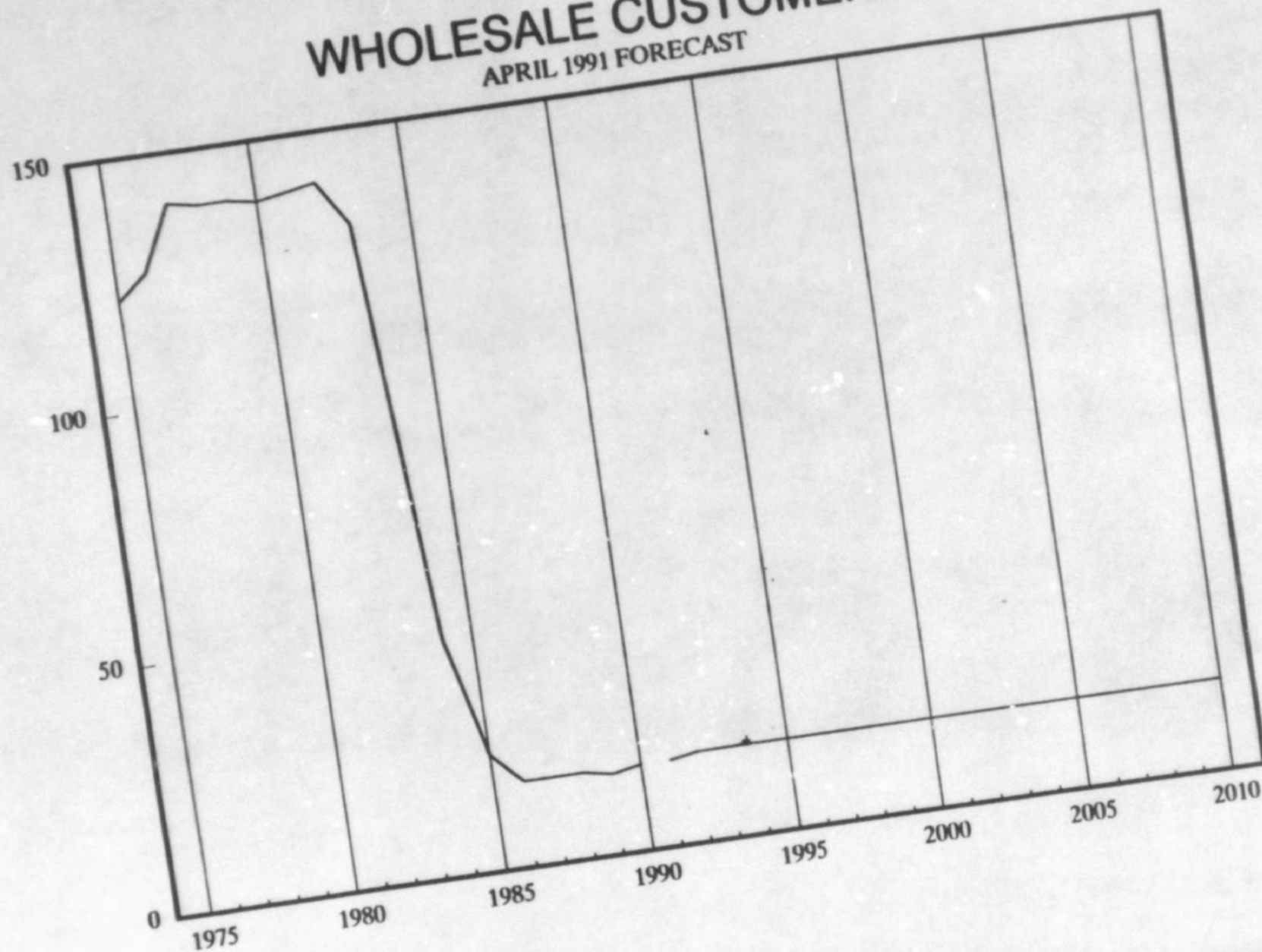
PUBLIC AUTHORITIES CUSTOMERS

APRIL 1991 FORECAST



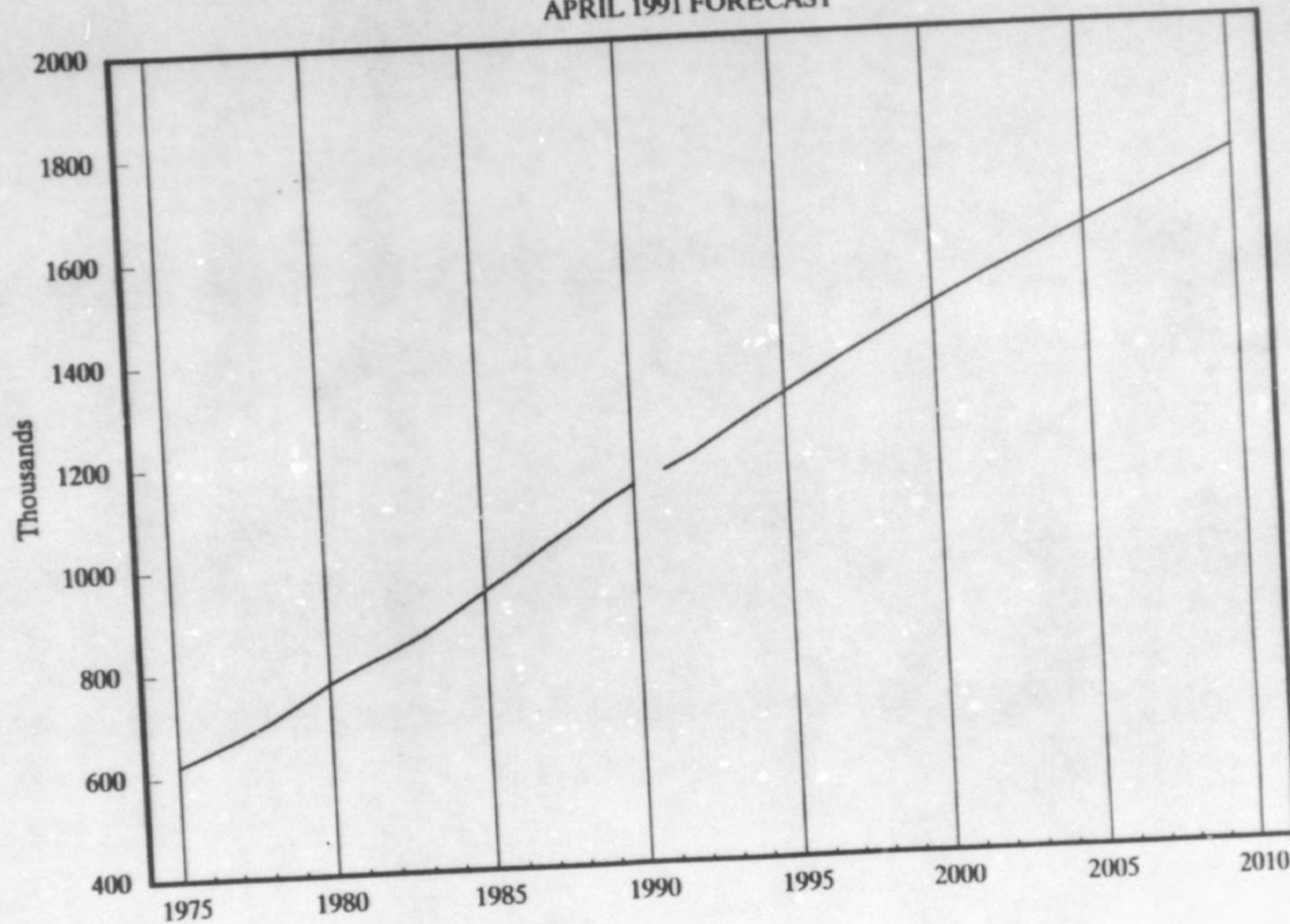
WHOLESALE CUSTOMERS

APRIL 1991 FORECAST



TOTAL SYSTEM CUSTOMERS

APRIL 1991 FORECAST

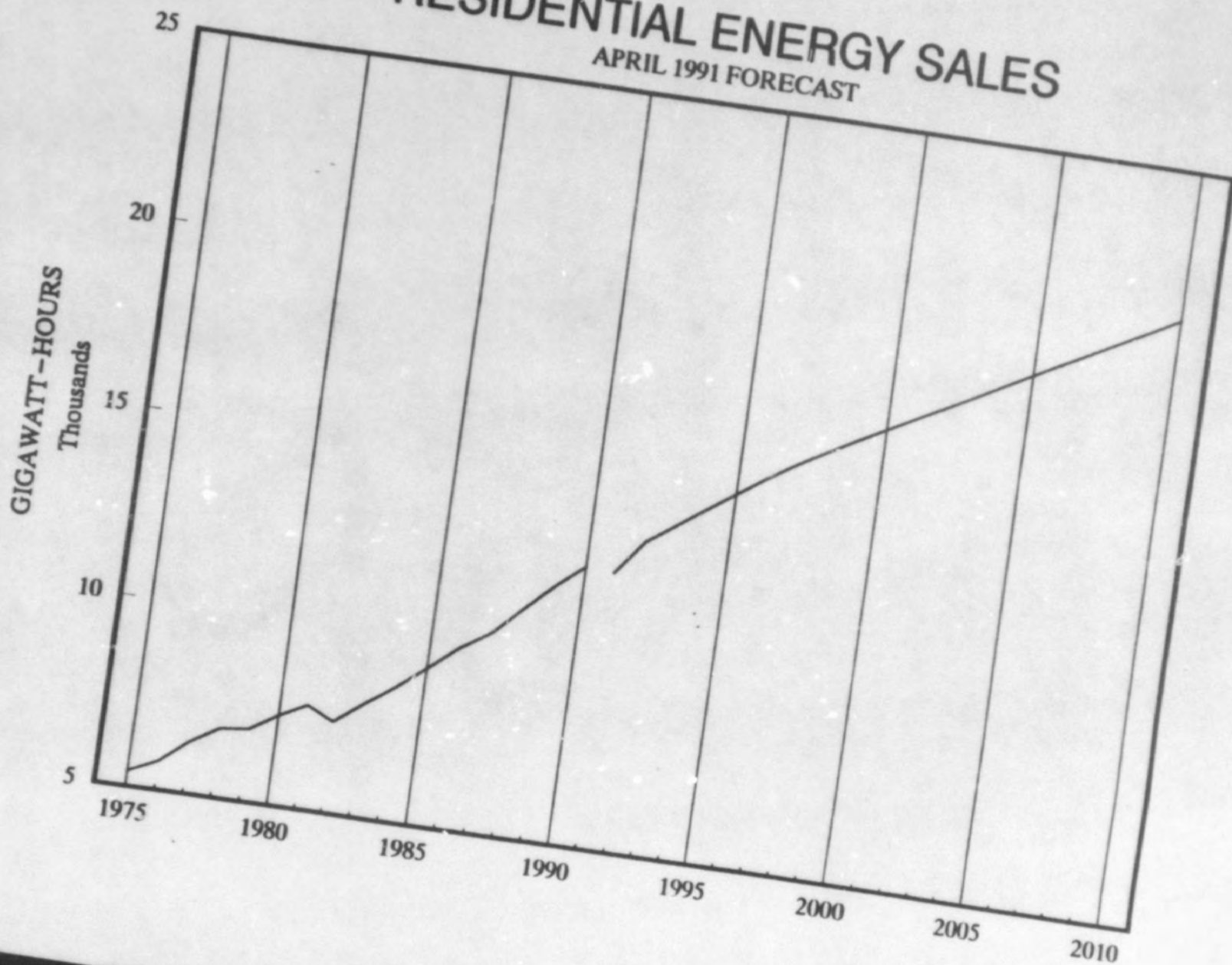


FLORIDA POWER CORPORATION NUMBER OF CUSTOMERS

	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	PUBLIC AUTHORITIES	REA	MUNICIPAL	TOTAL
HISTORY:	1975	557,893	60,598	1,488	1,554	147	103	19	621,780
	1976	579,044	62,277	1,489	1,648	261	107	20	644,846
	1977	601,062	64,783	1,655	1,692	283	109	31	669,615
	1978	627,894	68,029	1,795	1,733	267	108	31	699,677
	1979	660,010	70,100	1,995	1,800	1,589	107	32	735,633
	1980	693,398	71,431	2,156	1,444	3,698	104	34	772,265
	1981	720,590	74,413	2,241	1,459	3,945	105	34	802,787
	1982	745,155	76,226	2,336	1,397	4,556	108	32	829,810
	1983	771,047	81,249	2,409	1,393	5,319	107	24	861,548
	1984	804,092	86,803	2,540	1,504	5,813	25	22	900,799
	1985	838,671	91,817	2,611	1,668	6,189	2	21	940,976
	1986	872,441	96,843	2,705	1,822	6,599	2	15	980,427
	1987	908,640	102,657	2,877	1,935	7,096	2	15	1,023,222
	1988	941,439	106,899	2,942	2,038	7,636	2	15	1,060,971
	1989	977,449	111,079	3,021	2,105	8,108	2	14	1,101,818
	1990	1,007,806	113,595	3,115	2,255	8,711	2	15	1,135,499
1975-1990 AAGR		4.02	4.28	5.15	2.51	31.28	-23.11	-1.56	4.10
FORECAST:	1991	1,032,836	115,044	3,166	2,355	9,230	2	15	1,162,648
	1992	1,060,260	118,069	3,267	2,454	9,680	2	16	1,193,768
	1993	1,091,872	122,197	3,363	2,552	10,073	2	16	1,230,075
	1994	1,124,254	126,525	3,459	2,650	10,462	2	16	1,267,368
	1995	1,155,420	130,704	3,555	2,748	10,851	2	16	1,303,296
	1996	1,185,344	134,686	3,651	2,846	11,240	2	16	1,337,785
	1997	1,214,222	138,465	3,747	2,944	11,629	2	16	1,371,025
	1998	1,242,202	142,128	3,843	3,042	12,018	2	16	1,403,251
	1999	1,269,401	145,689	3,939	3,140	12,407	2	16	1,434,594
	2000	1,295,936	149,164	4,035	3,238	12,796	2	16	1,465,187
1991-2000 AAGR		2.55	2.93	2.73	3.60	3.70	0.00	0.72	2.60
	2001	1,321,916	152,566	4,131	3,336	13,185	2	16	1,495,152
	2002	1,347,415	155,906	4,227	3,434	13,574	2	16	1,524,574
	2003	1,372,500	159,191	4,323	3,532	13,963	2	16	1,553,527
	2004	1,397,238	162,431	4,419	3,630	14,352	2	16	1,582,088
	2005	1,421,694	165,634	4,515	3,728	14,741	2	16	1,610,330
	2006	1,445,888	168,803	4,611	3,826	15,130	2	16	1,638,276
	2007	1,469,840	171,940	4,707	3,924	15,519	2	16	1,665,948
	2008	1,493,570	175,048	4,803	4,022	15,908	2	16	1,693,369
	2009	1,517,088	178,126	4,899	4,120	16,297	2	16	1,720,550
	2010	1,540,404	181,182	4,995	4,218	16,686	2	16	1,747,503
2001-2010 AAGR		1.71	1.93	2.13	2.64	2.65	0.00	0.00	1.75
1991-2010 AAGR		2.13	2.42	2.43	3.12	3.17	0.00	0.34	2.17

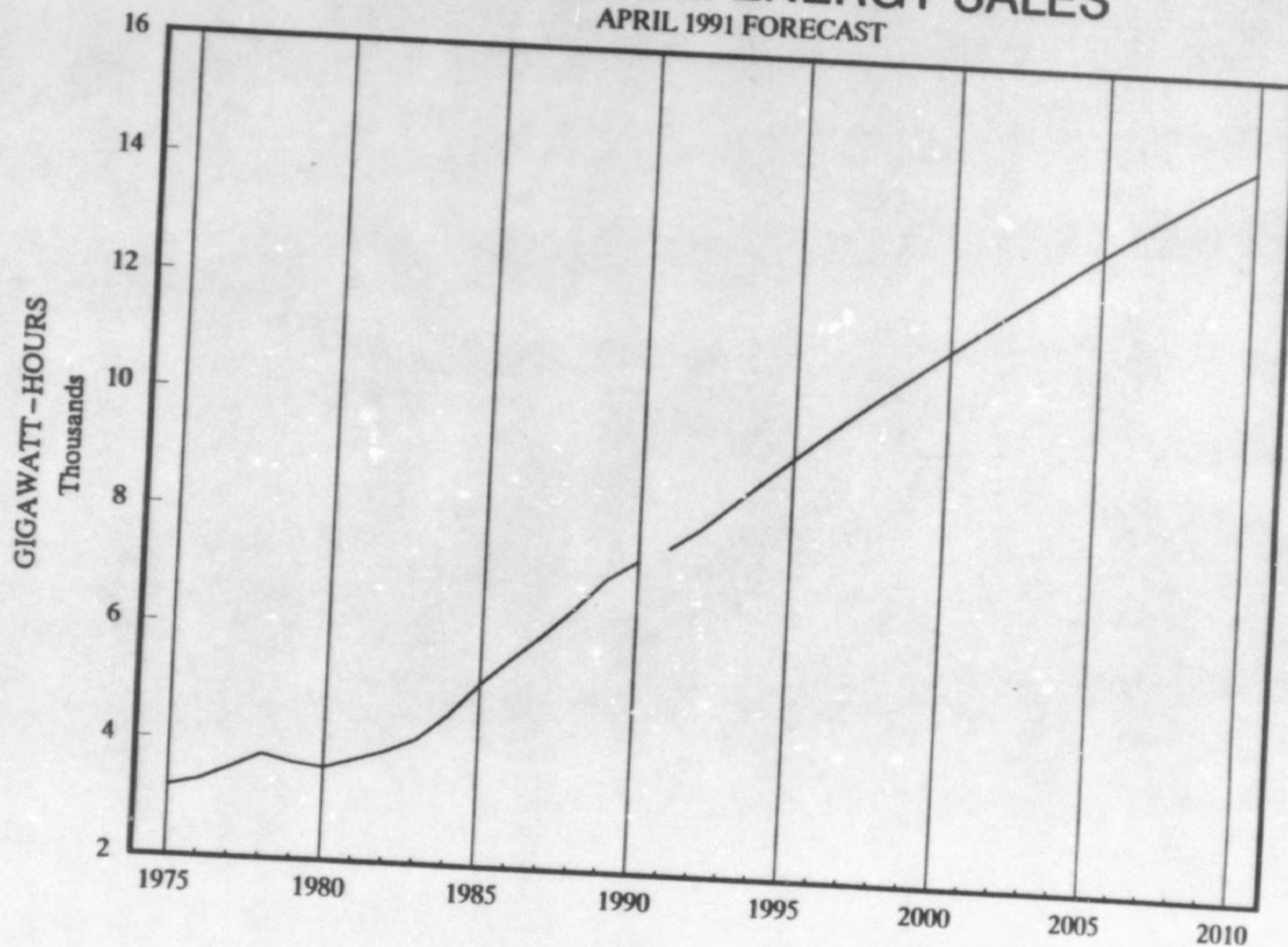
RESIDENTIAL ENERGY SALES

APRIL 1991 FORECAST



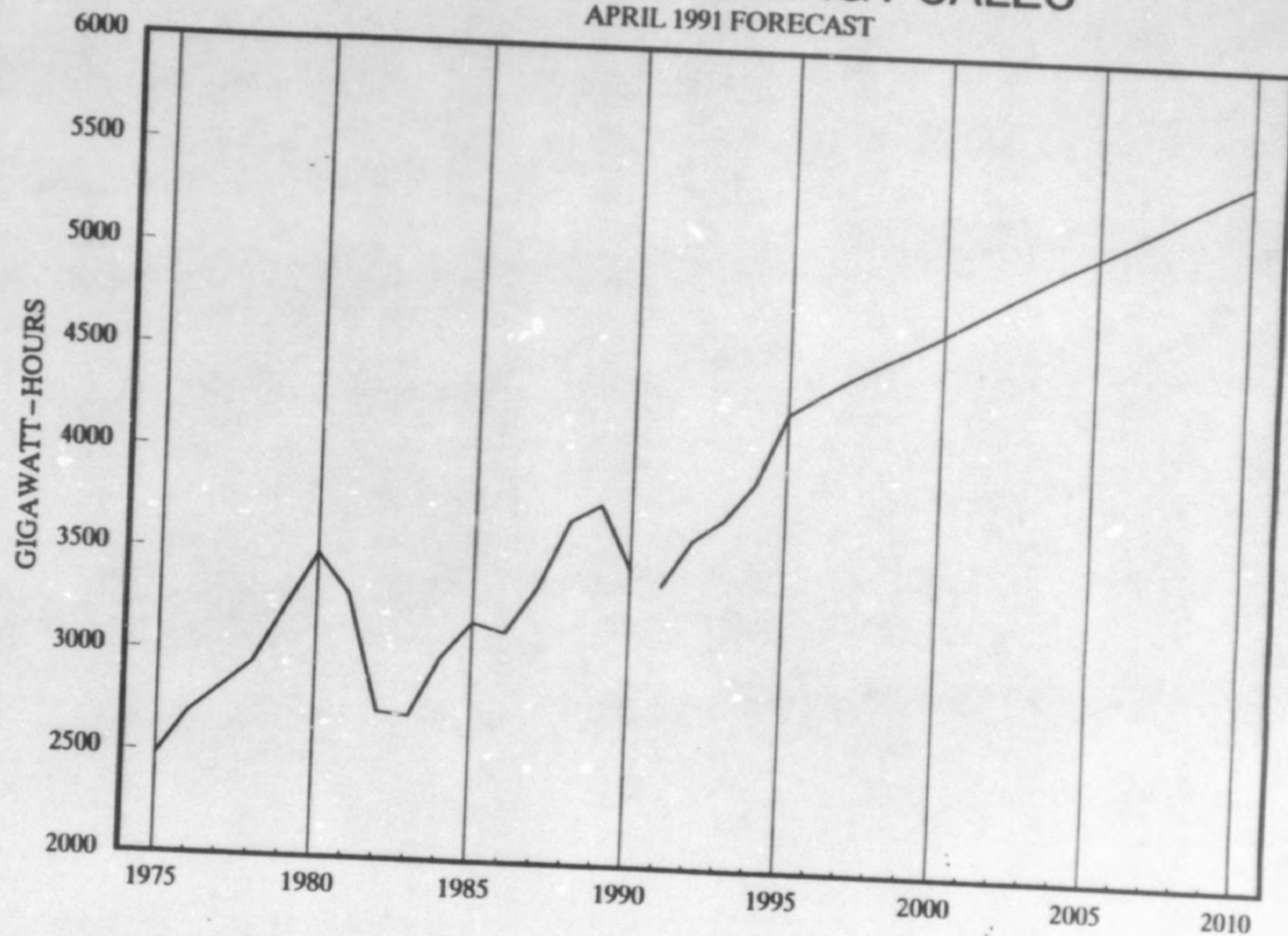
COMMERCIAL ENERGY SALES

APRIL 1991 FORECAST



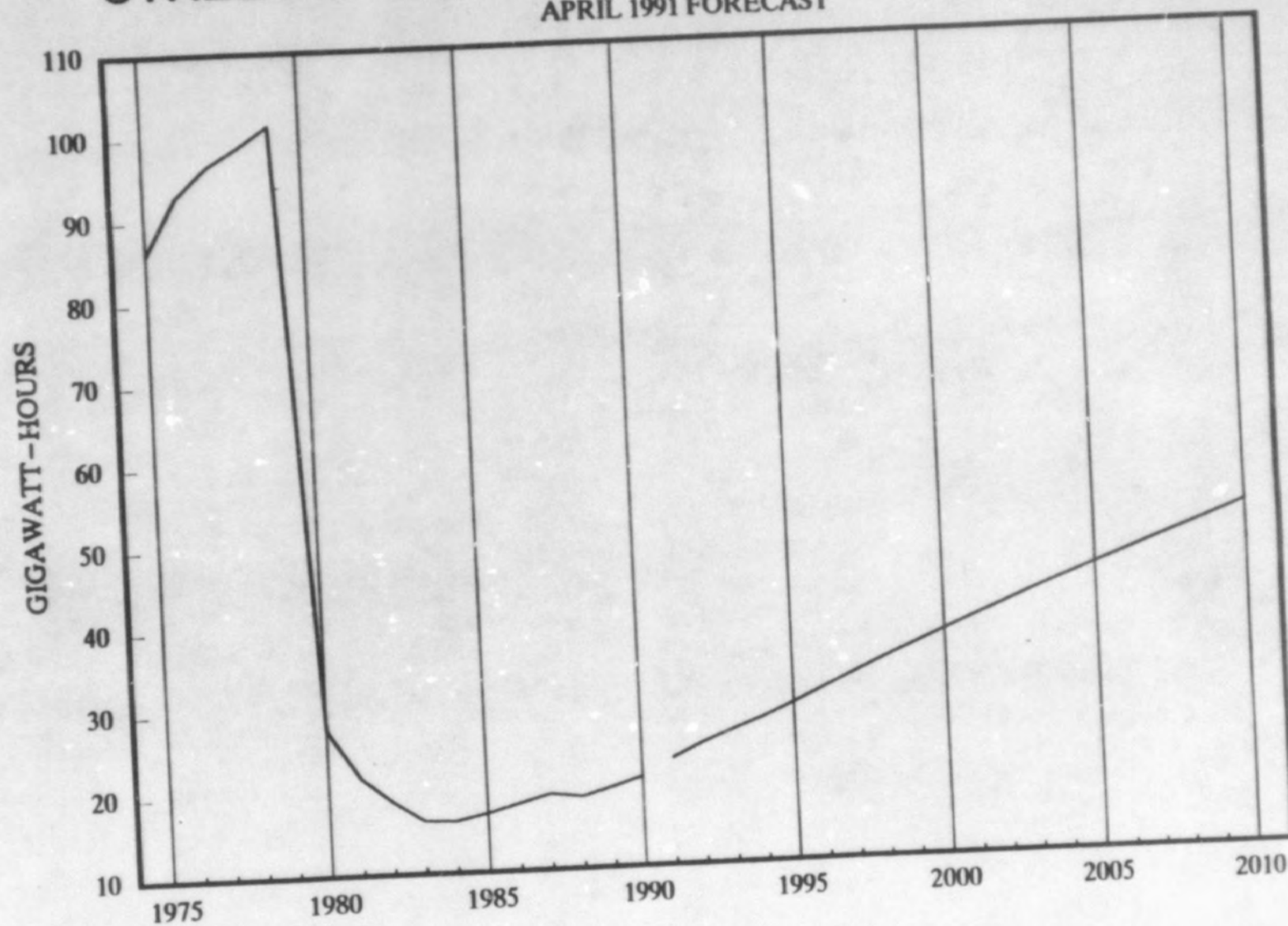
INDUSTRIAL ENERGY SALES

APRIL 1991 FORECAST



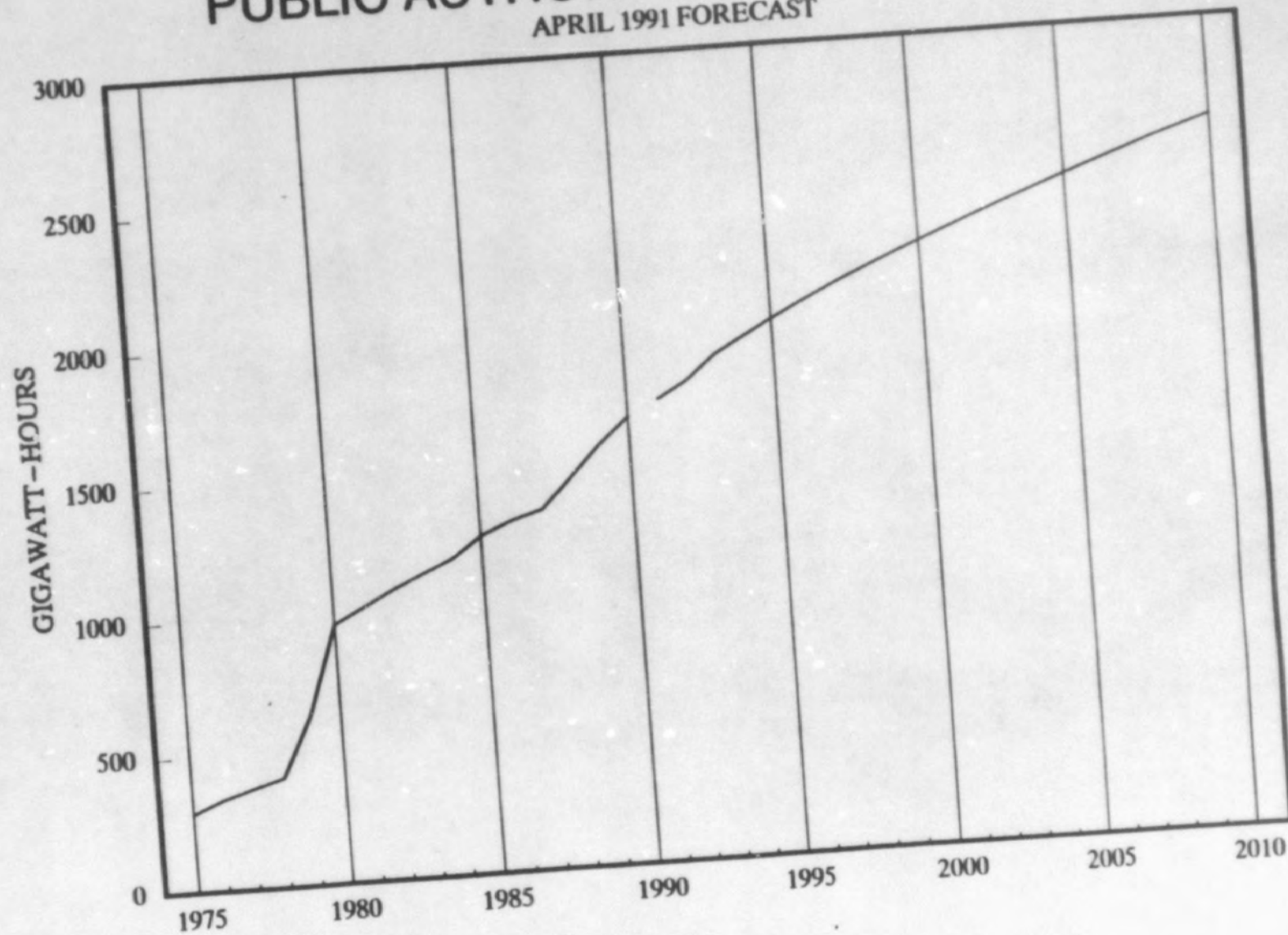
STREET & HIGHWAY LIGHTING ENERGY SALES

APRIL 1991 FORECAST



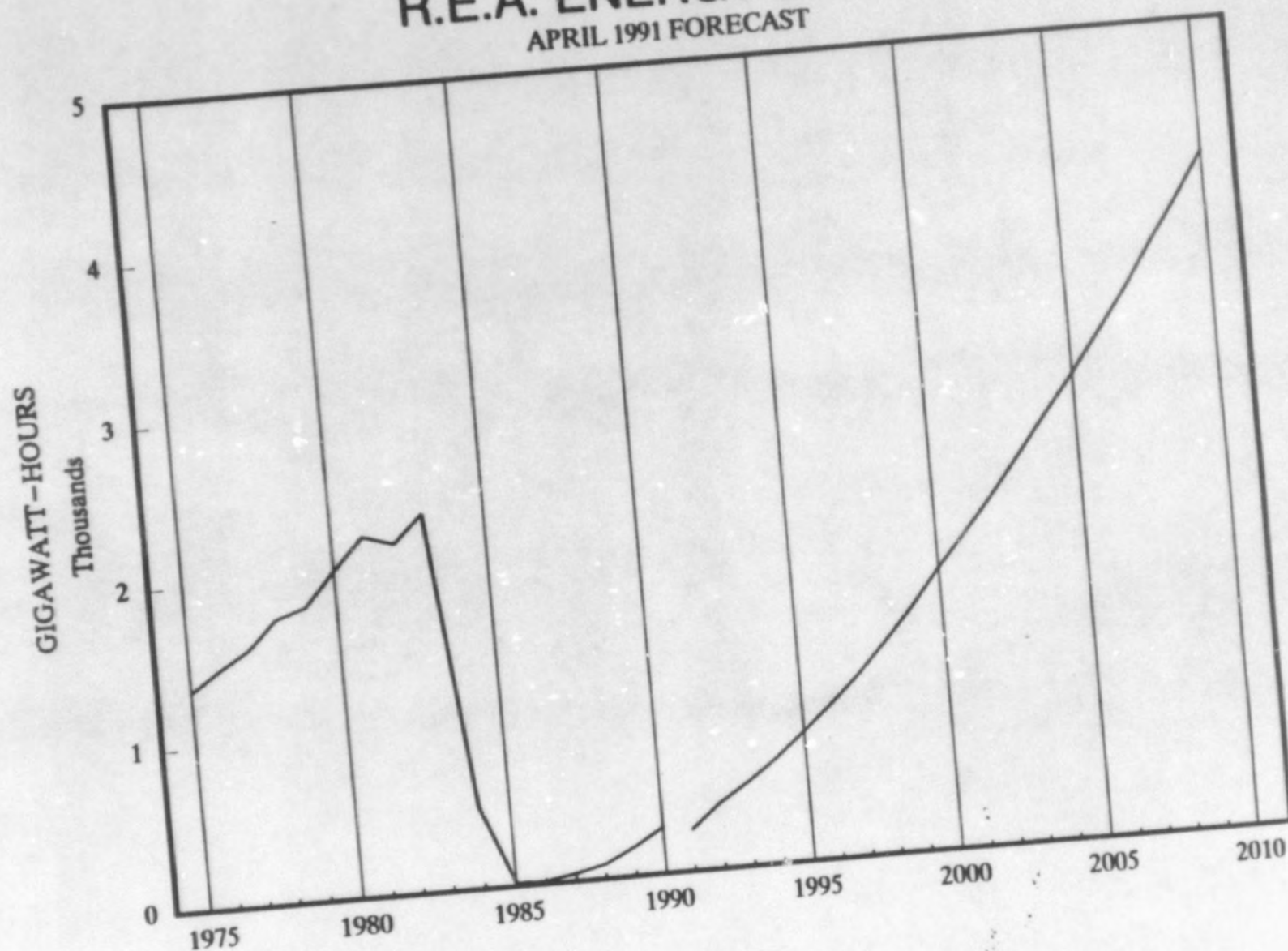
PUBLIC AUTHORITIES ENERGY SALES

APRIL 1991 FORECAST



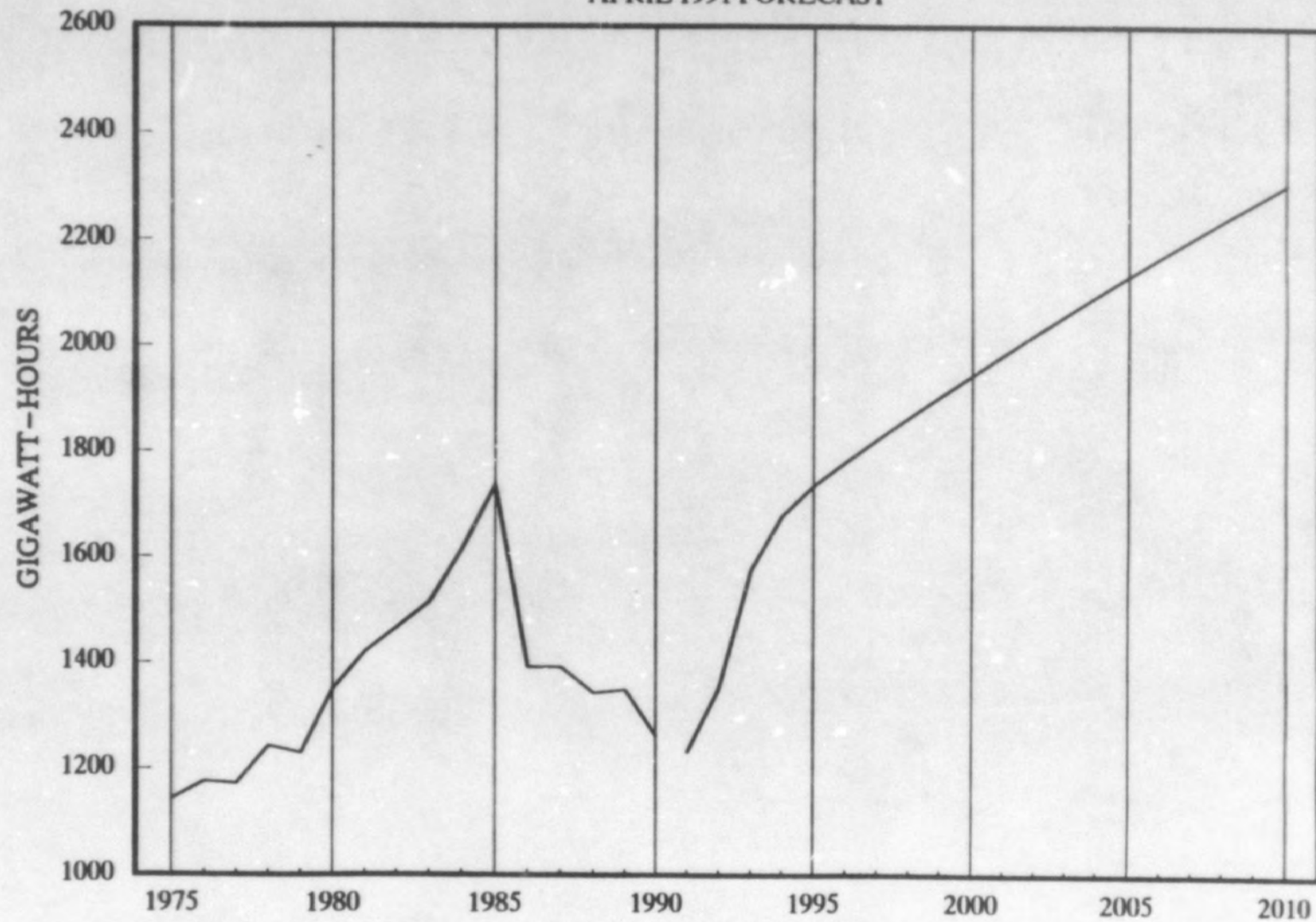
R.E.A. ENERGY SALES

APRIL 1991 FORECAST



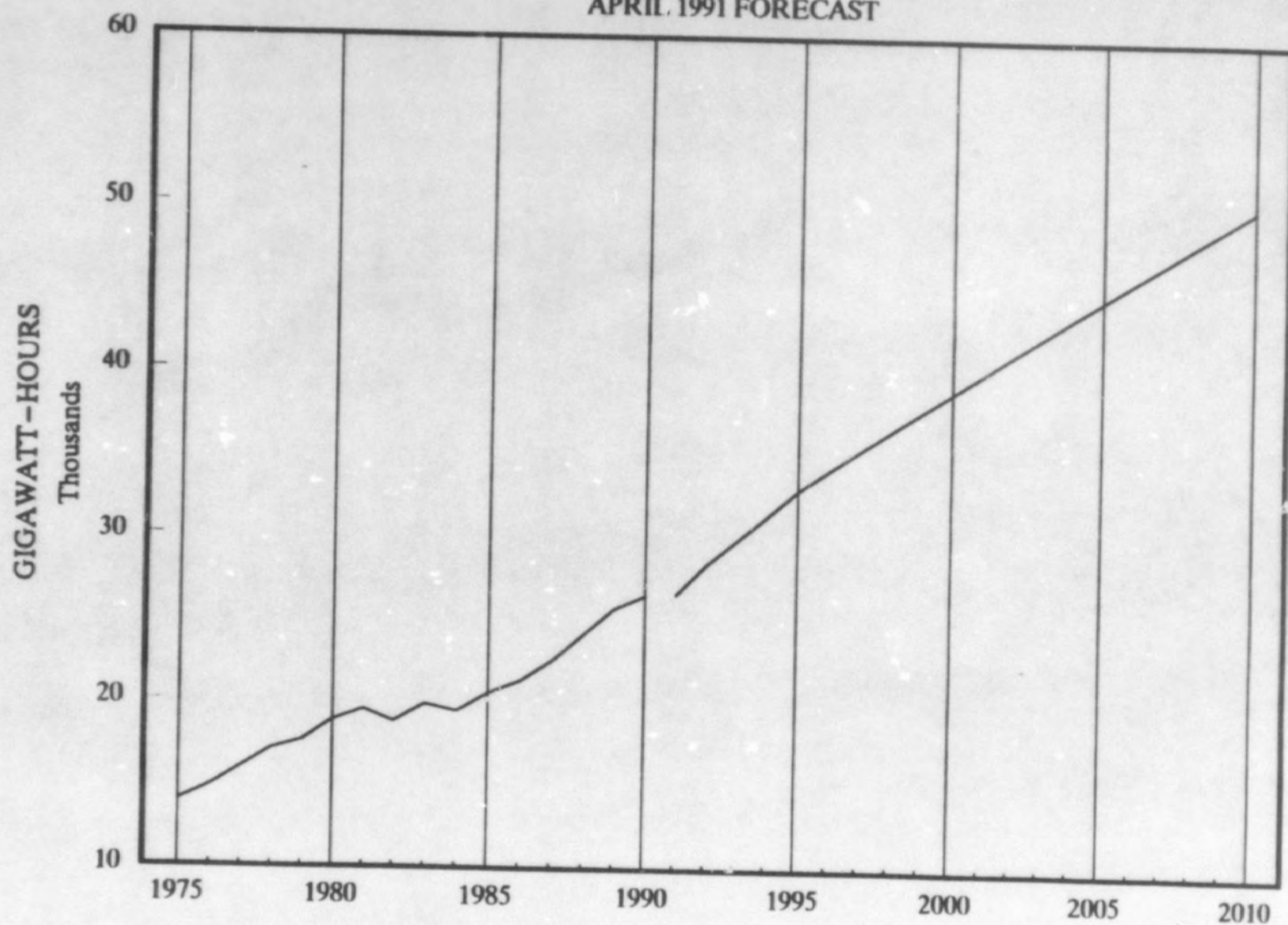
MUNICIPAL ENERGY SALES

APRIL 1991 FORECAST



TOTAL SYSTEM ENERGY SALES

APRIL 1991 FORECAST



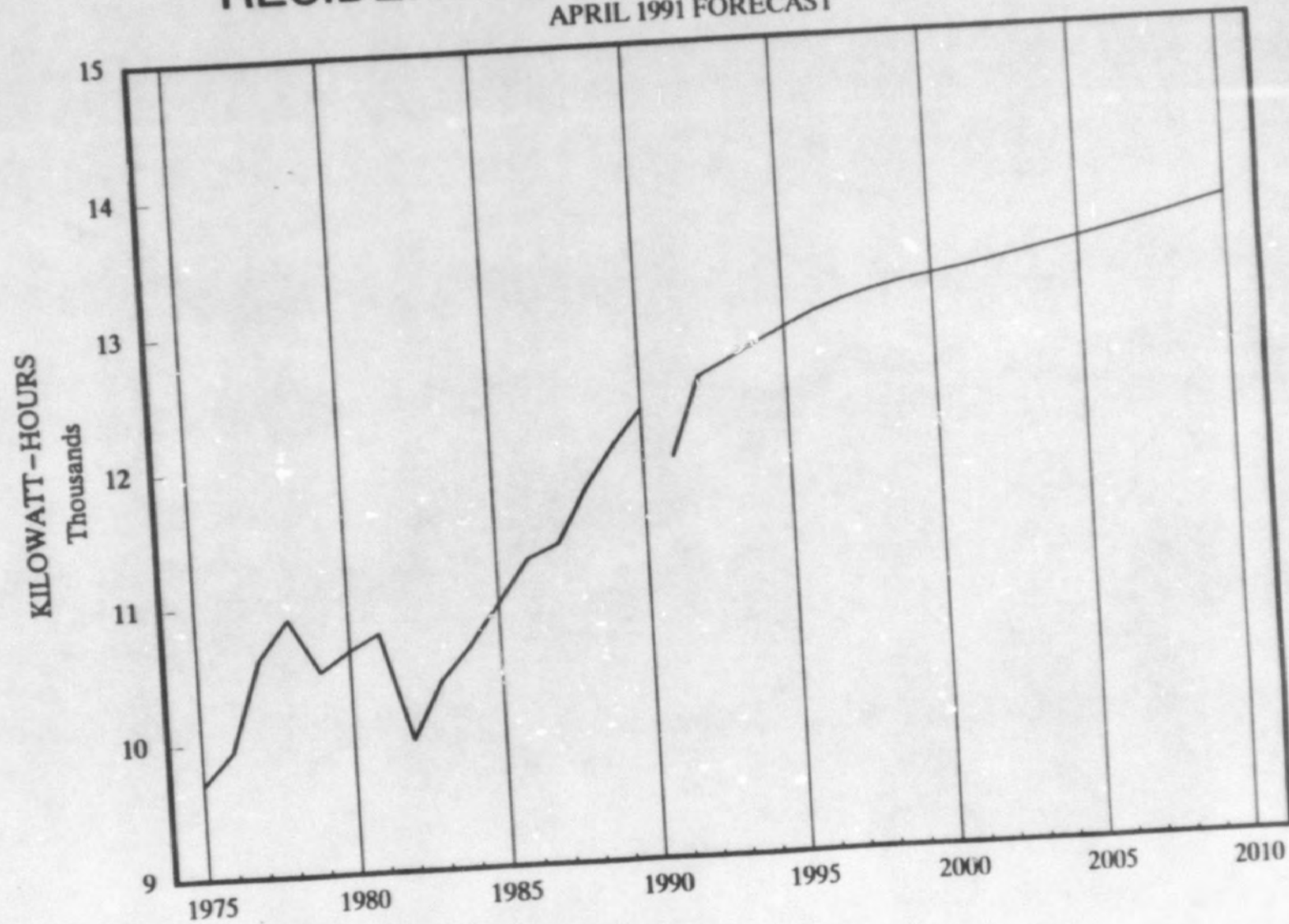
FLORIDA POWER CORPORATION GWH ENERGY SALES

	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	STREET LIGHTING	PUBLIC AUTHORITIES	REA	MUNICIPAL	TOTAL
HISTORY:	1975	5,412	3,187	2,479	86	290	1,347	1,142	13,944
	1976	5,751	3,298	2,691	93	337	1,472	1,176	14,817
	1977	6,374	3,527	2,813	96	371	1,583	1,171	15,935
	1978	6,839	3,766	2,942	99	404	1,754	1,243	17,047
	1979	6,927	3,646	3,216	101	634	1,816	1,229	17,561
	1980	7,380	3,581	3,481	28	960	2,028	1,350	18,808
	1981	7,752	3,735	3,268	22	1,017	2,222	1,420	19,457
	1982	7,425	3,895	2,716	19	1,076	2,164	1,466	18,761
	1983	8,010	4,119	2,701	18	1,127	2,334	1,514	19,820
	1984	8,554	4,548	2,989	16	1,173	499	1,615	19,393
	1985	9,175	5,107	3,166	17	1,251	20	1,737	20,473
	1986	9,819	5,573	3,122	18	1,301	16	1,392	21,241
	1987	10,319	6,016	3,349	19	1,336	48	1,393	22,480
	1988	11,066	6,479	3,681	19	1,447	90	1,343	24,124
	1989	11,787	6,990	3,766	20	1,561	180	1,349	25,653
	1990	12,416	7,329	3,456	21	1,658	285	1,263	26,426
1975-1990 AAGR		5.69	5.71	2.24	-9.04	12.33	-9.83	0.67	4.35
FORECAST:	1991	12,349	7,568	3,379	23	1,715	256	1,232	26,522
	1992	13,292	7,314	3,605	25	1,776	408	1,353	28,373
	1993	13,801	8,332	3,711	26	1,864	524	1,576	29,534
	1994	14,345	8,769	3,895	27	1,925	652	1,677	31,291
	1995	14,870	9,196	4,242	29	1,984	802	1,735	32,858
	1996	15,379	9,609	4,335	31	2,040	957	1,781	34,131
	1997	15,851	10,004	4,422	32	2,093	1,122	1,824	35,349
	1998	16,291	10,385	4,502	34	2,143	1,309	1,865	36,529
	1999	16,713	10,760	4,575	36	2,191	1,512	1,905	37,692
	2000	17,113	11,127	4,651	37	2,237	1,735	1,944	38,843
1991-2000 AAGR		3.69	4.38	3.61	5.55	2.99	23.70	5.20	4.33
	2001	17,506	11,488	4,733	39	2,281	1,945	1,982	39,973
	2002	17,901	11,845	4,817	40	2,324	2,165	2,020	41,113
	2003	18,297	12,196	4,902	42	2,367	2,393	2,058	42,254
	2004	18,693	12,543	4,983	43	2,408	2,635	2,095	43,399
	2005	19,085	12,882	5,055	44	2,448	2,869	2,131	44,516
	2006	19,483	13,215	5,127	46	2,488	3,117	2,167	45,644
	2007	19,880	13,539	5,207	47	2,526	3,372	2,203	46,774
	2008	20,280	13,856	5,287	49	2,563	3,644	2,238	47,916
	2009	20,683	14,163	5,365	50	2,599	3,903	2,272	49,035
	2010	21,085	14,462	5,437	51	2,634	4,178	2,306	50,152
2001-2010 AAGR		2.09	2.59	1.55	3.21	1.61	8.87	1.69	2.55
1991-2010 AAGR		2.86	3.47	2.53	4.35	2.28	15.84	3.35	3.41

USE PER CUSTOMER FORECAST

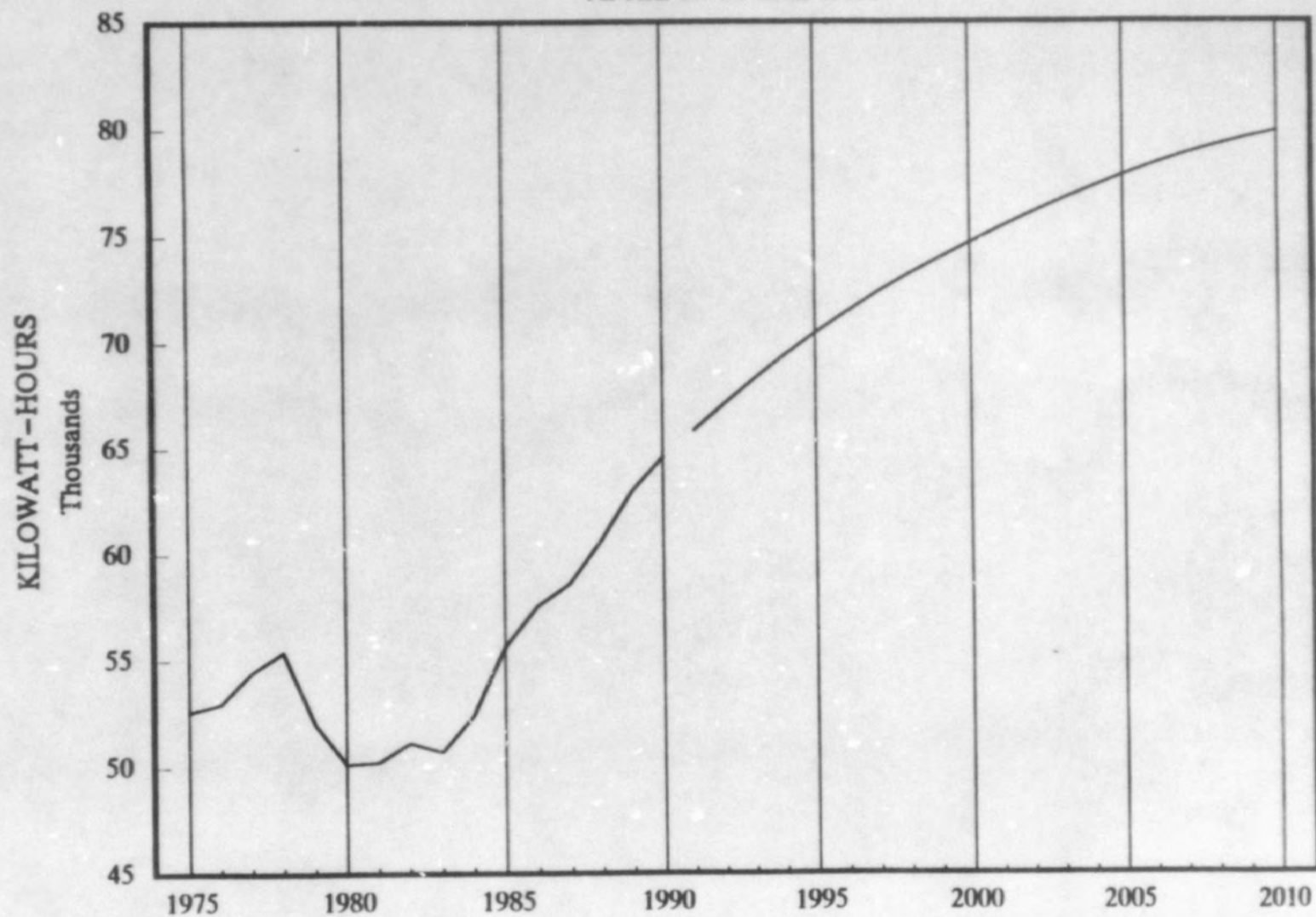
RESIDENTIAL KWH-PER-CUSTOMER

APRIL 1991 FORECAST



COMMERCIAL KWH—PER—CUSTOMER

APRIL 1991 FORECAST



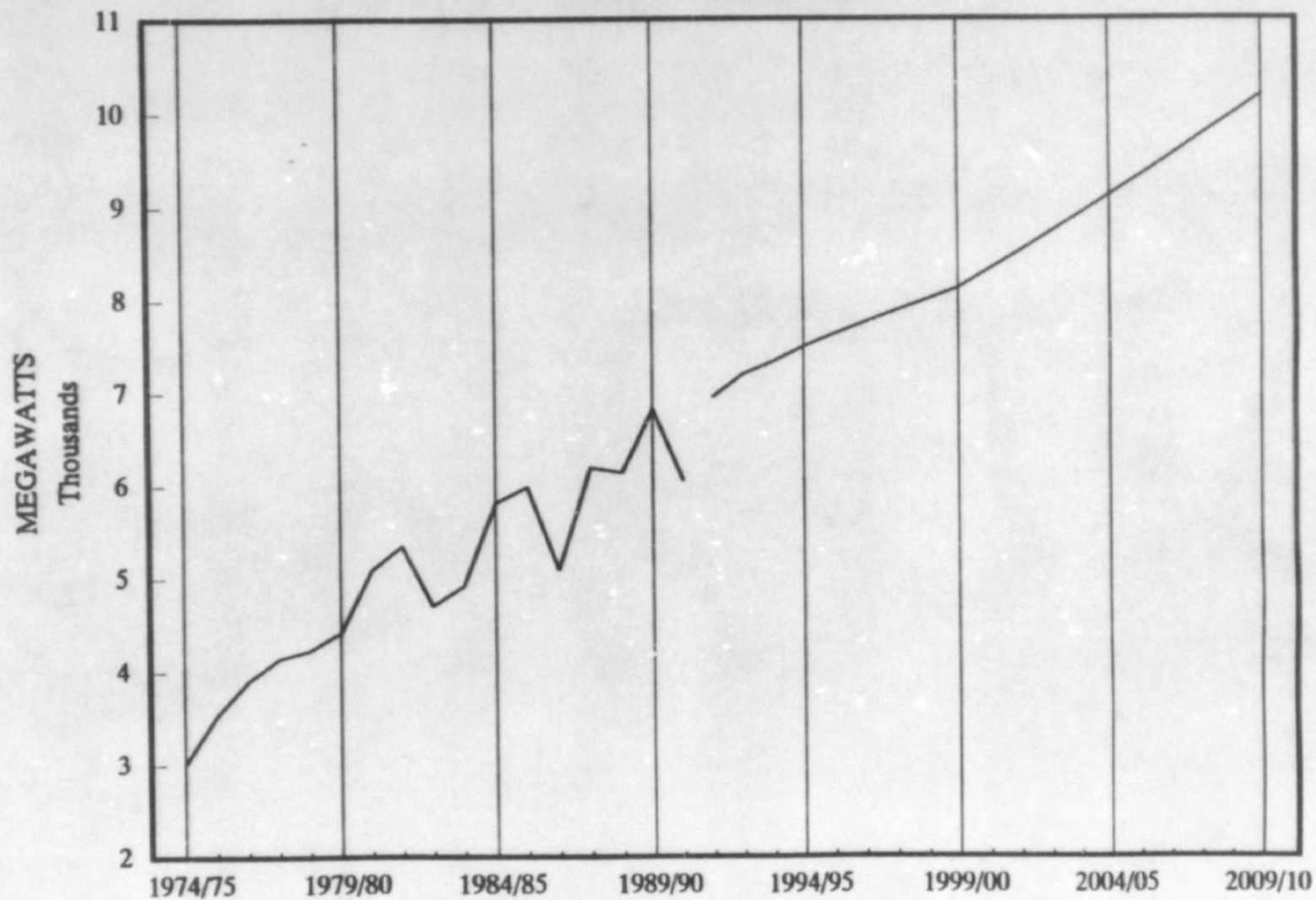
FLORIDA POWER CORPORATION KWH-PER-CUSTOMER

YEAR	RESIDENTIAL	COMMERCIAL
HISTORY:		
1975	9,701	52,600
1976	9,932	52,958
1977	10,604	54,437
1978	10,895	55,362
1979	10,496	52,015
1980	10,643	50,134
1981	10,758	50,195
1982	9,964	51,101
1983	10,388	50,691
1984	10,638	52,391
1985	10,940	55,617
1986	11,255	57,547
1987	11,356	58,607
1988	11,754	60,612
1989	12,059	62,926
1990	12,319	64,516
1975-1990 AAGR	1.61	1.37
FORECAST:		
1991	11,957	65,781
1992	12,536	67,025
1993	12,640	68,182
1994	12,760	69,310
1995	12,870	70,361
1996	12,974	71,343
1997	13,054	72,252
1998	13,115	73,071
1999	13,166	73,854
2000	13,205	74,594
1991-2000 AAGR	1.11	1.41
2001	13,243	75,299
2002	13,285	75,977
2003	13,331	76,615
2004	13,378	77,218
2005	13,424	77,776
2006	13,475	78,286
2007	13,525	78,745
2008	13,578	79,153
2009	13,633	79,512
2010	13,688	79,818
2001-2010 AAGR	0.37	0.65
1991-2010 AAGR	0.71	1.02

SEASONAL PEAK DEMAND FORECAST

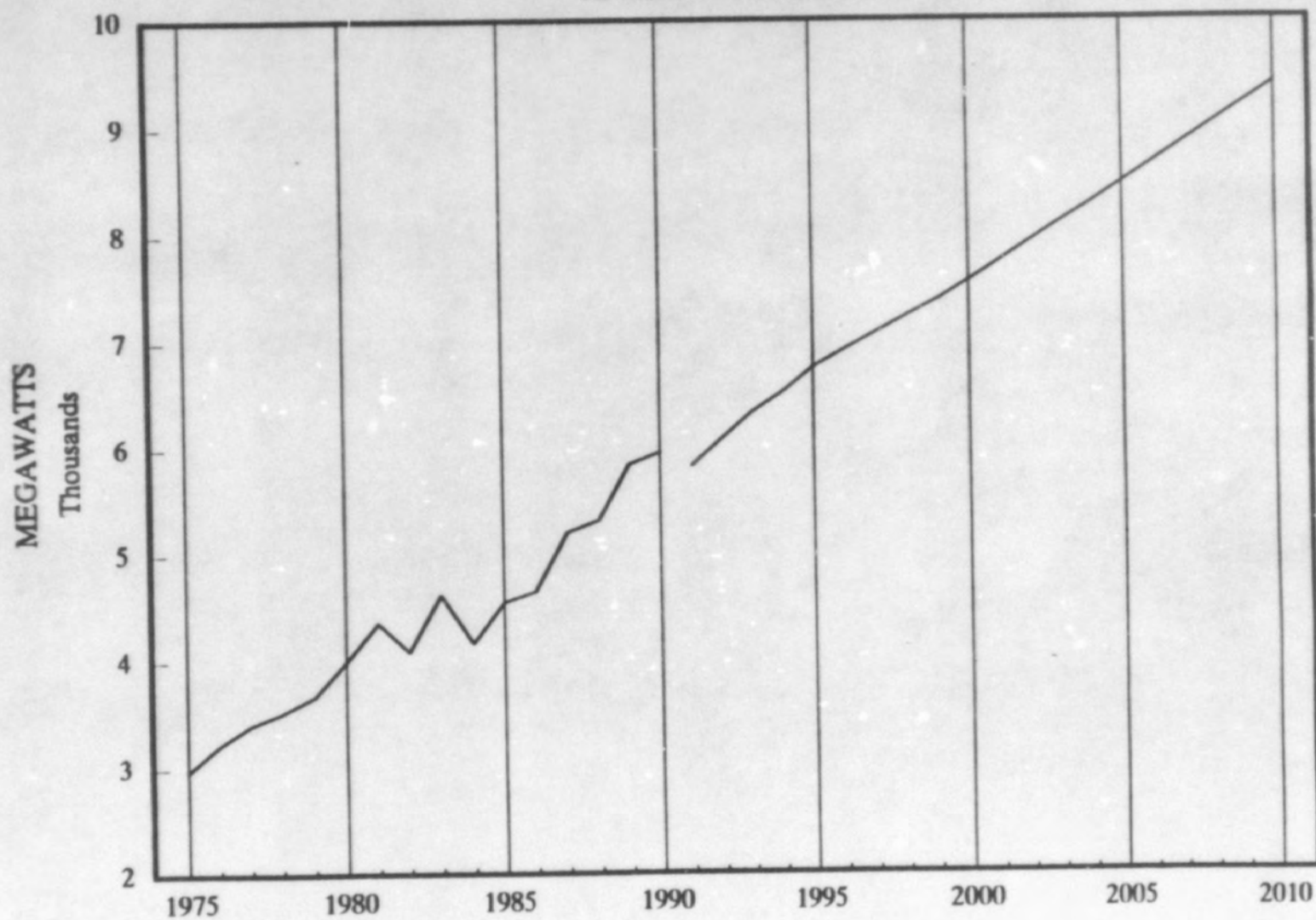
WINTER PEAK DEMAND

APRIL 1991 FORECAST



SUMMER PEAK DEMAND

APRIL 1991 FORECAST



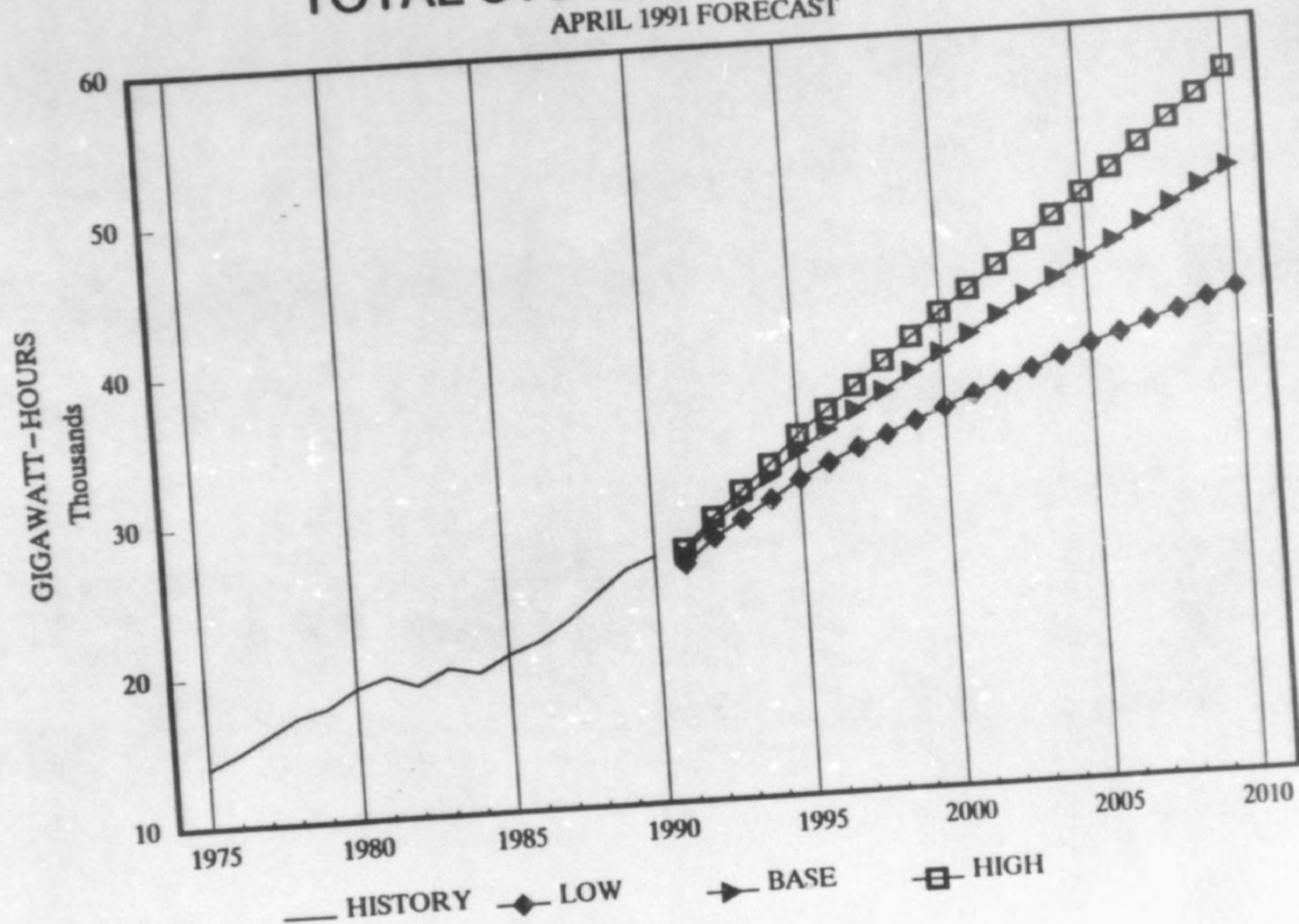
FLORIDA POWER CORPORATION SEASONAL PEAK MW DEMAND

	YEAR	WINTER	YEAR	SUMMER
HISTORY:	1974/75	3,010	1975	
	1975/76	3,530	1976	2,975
	1976/77	3,899	1977	3,223
	1977/78	4,135	1978	3,407
	1978/79	4,224	1979	3,521
	1979/80	4,419	1980	3,667
	1980/81	5,088	1981	3,995
	1981/82	5,347	1982	4,355
	1982/83	4,701	1983	4,086
	1983/84	4,913	1984	4,610
	1984/85	5,813	1985	4,163
	1985/86	5,977	1986	4,548
	1986/87	5,087	1987	4,644
	1987/88	6,188	1988	5,196
	1988/89	6,137	1989	5,309
	1989/90	6,817	1990	5,832
	1990/91	6,056		5,946
	1974/75-1990/91 AAGR	4.47	1975-1990 AAGR	4.72
FORECAST:	1991/92	6,948	1991	5,821
	1992/93	7,193	1992	6,076
	1993/94	7,324	1993	6,318
	1994/95	7,488	1994	6,500
	1995/96	7,621	1995	6,734
	1996/97	7,748	1996	6,896
	1997/98	7,866	1997	7,053
	1998/99	7,982	1998	7,203
	1999/00	8,105	1999	7,354
	1991/92-1999/00 AAGR	1.94	2000	7,531
			1991-2000 AAGR	2.90
	2000/01	8,301	2001	7,716
	2001/02	8,497	2002	7,901
	2002/03	8,697	2003	8,087
	2003/04	8,897	2004	8,269
	2004/05	9,100	2005	8,455
	2005/06	9,310	2006	8,642
	2006/07	9,522	2007	8,827
	2007/08	9,741	2008	9,014
	2008/09	9,959	2009	9,201
	2009/10	10,181	2010	9,387
	2000/01-2009/10 AAGR	2.29	2001-2010 AAGR	2.20
	1991/92-2009/10 AAGR	2.15	1991-2010 AAGR	2.55

HIGH AND LOW SENSITIVITY CASES

TOTAL SYSTEM ENERGY SALES

APRIL 1991 FORECAST



FLORIDA POWER CORPORATION TOTAL SYSTEM GWH ENERGY SALES

HISTORY:	YEAR	ACTUAL
	1975	13,944
	1976	14,817
	1977	15,935
	1978	17,047
	1979	17,569
	1980	18,808
	1981	19,457
	1982	18,761
	1983	19,820
	1984	19,393
	1985	20,473
	1986	21,241
	1987	22,480
	1988	24,124
	1989	25,653
	1990	26,426

YEAR	ACTUAL
1975	13,944
1976	14,817
1977	15,935
1978	17,047
1979	17,569
1980	18,808
1981	19,457
1982	18,761
1983	19,820
1984	19,393
1985	20,473
1986	21,241
1987	22,480
1988	24,124
1989	25,653
1990	26,426

1975-1990 AAGR 4.35

FORECAST:

YEAR	LOW	% DIFF	BASE	% DIFF	HIGH
1991	25,809	-2.69	26,521	1.18	26,835
1992	27,431	-3.32	28,373	1.50	28,797
1993	28,578	-4.21	29,834	2.01	30,433
1994	29,735	-4.97	31,291	2.55	32,088
1995	30,971	-5.74	32,858	3.30	33,944
1996	31,931	-6.45	34,131	3.89	35,459
1997	32,836	-7.11	35,349	4.61	36,980
1998	33,590	-8.04	36,529	5.40	38,501
1999	34,377	-8.79	37,692	6.03	39,965
2000	35,158	-9.49	38,843	6.77	41,472

1991-2000 AAGR 3.49

LOW	% DIFF	BASE	% DIFF	HIGH
35,918	-10.14	39,973	7.32	42,901
36,646	-10.87	41,113	8.02	44,409
37,396	-11.50	42,254	8.71	45,935
38,115	-12.17	43,399	9.39	47,473
38,836	-12.76	44,516	9.86	48,907
39,465	-13.54	45,644	10.51	50,439
40,179	-14.10	46,774	11.13	51,979
40,813	-14.82	47,916	11.71	53,527
41,517	-15.33	49,035	12.15	54,995
42,127	-16.00	50,152	12.88	56,614

4.96

YEAR	LOW	% DIFF	BASE	% DIFF	HIGH
2001	35,918	-10.14	39,973	7.32	42,901
2002	36,646	-10.87	41,113	8.02	44,409
2003	37,396	-11.50	42,254	8.71	45,935
2004	38,115	-12.17	43,399	9.39	47,473
2005	38,836	-12.76	44,516	9.86	48,907
2006	39,465	-13.54	45,644	10.51	50,439
2007	40,179	-14.10	46,774	11.13	51,979
2008	40,813	-14.82	47,916	11.71	53,527
2009	41,517	-15.33	49,035	12.15	54,995
2010	42,127	-16.00	50,152	12.88	56,614

2001-2010 AAGR 1.79

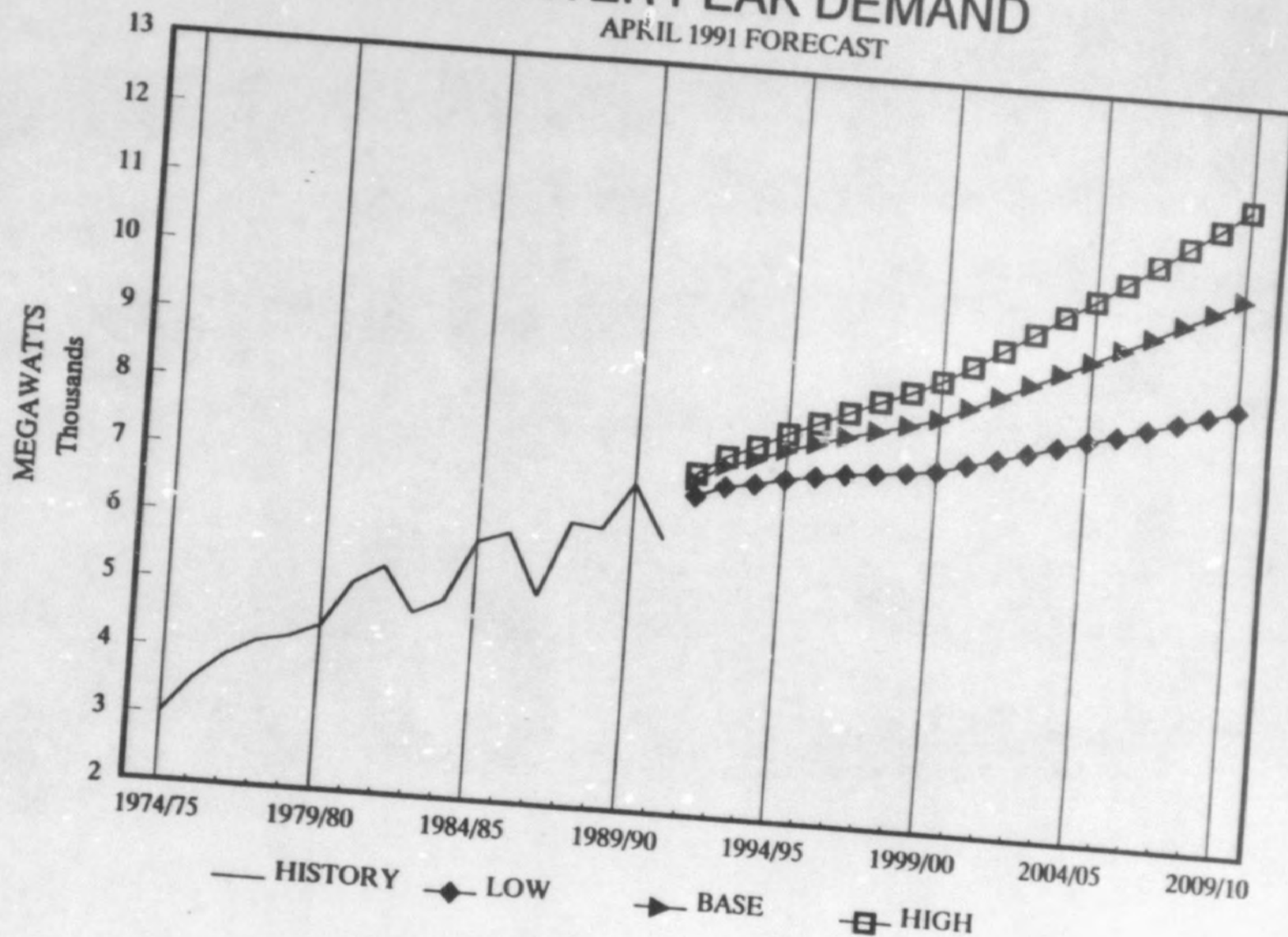
2.55 3.13

1991-2010 AAGR 2.61

3.41 4.01

WINTER PEAK DEMAND

APRIL 1991 FORECAST

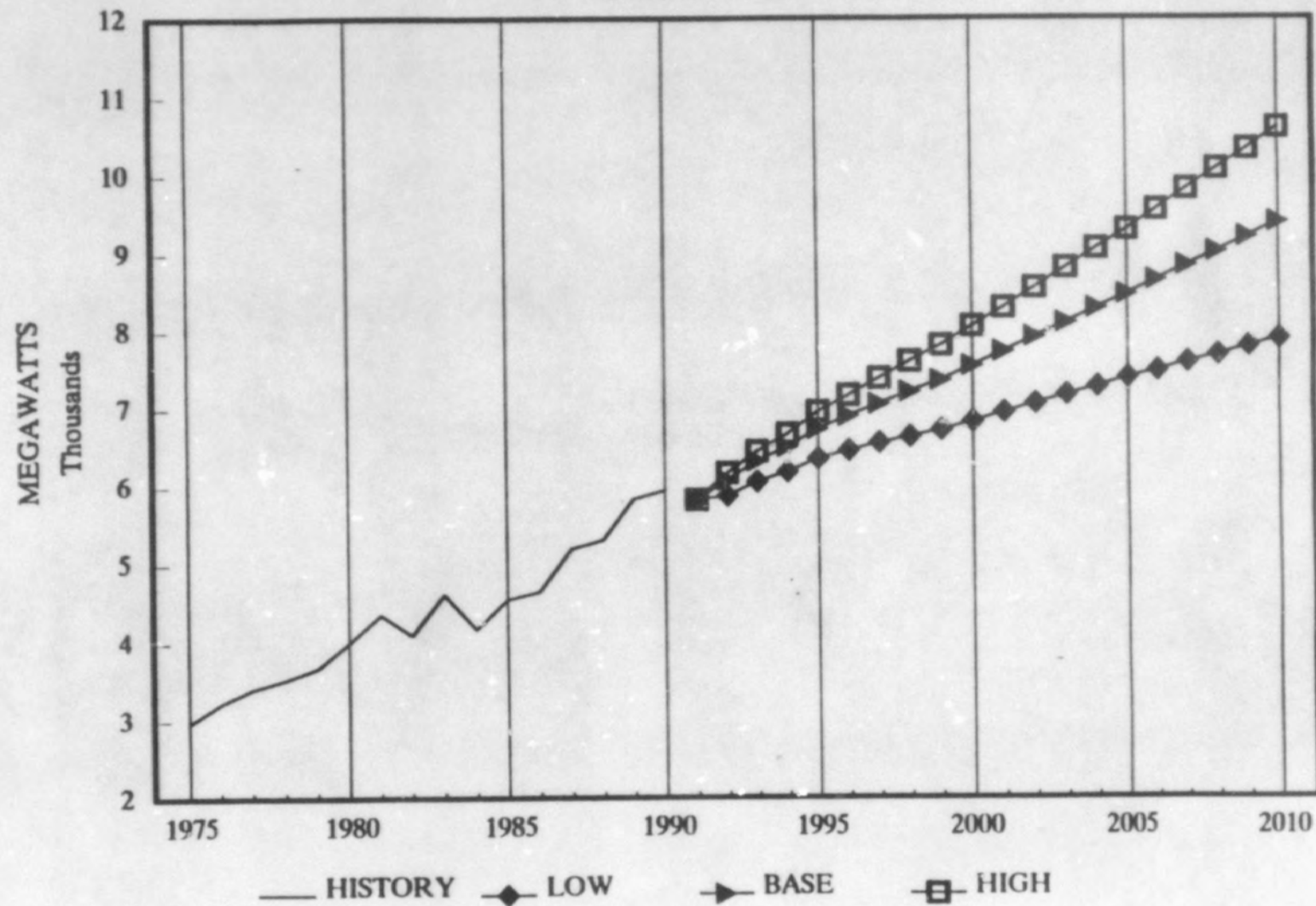


FLORIDA POWER CORPORATION WINTER PEAK MW DEMAND

	YEAR	ACTUAL				
HISTORY:	1974/75	3,010				
	1975/76	3,530				
	1976/77	3,899				
	1977/78	4,135				
	1978/79	4,224				
	1979/80	4,419				
	1980/81	5,088				
	1981/82	5,347				
	1982/83	4,701				
	1983/84	4,913				
	1984/85	5,813				
	1985/86	5,977				
	1986/87	5,087				
	1987/88	6,168				
	1988/89	6,137				
	1989/90	6,817				
	1990/91	6,056				
	1974/75-1990/91 AAGR	4.47				
	YEAR	LOW	% DIFF	BASE	% DIFF	HIGH
FORECAST:	1991/92	6,717	-3.32	6,948	1.50	7,052
	1992/93	6,890	-4.21	7,193	2.00	7,337
	1993/94	6,960	-4.97	7,324	2.54	7,510
	1994/95	7,058	-5.74	7,488	3.30	7,735
	1995/96	7,130	-6.44	7,621	3.88	7,917
	1996/97	7,197	-7.11	7,748	4.61	8,105
	1997/98	7,233	-8.05	7,866	5.40	8,291
	1998/99	7,280	-8.79	7,982	6.04	8,464
	1999/00	7,336	-9.49	8,105	6.77	8,654
1991/92-1999/00 AAGR	1.11			1.94		2.59
	2000/01	7,459	-10.14	8,301	7.32	8,909
	2001/02	7,574	-10.86	8,497	8.01	9,178
	2002/03	7,697	-11.50	8,697	8.72	9,455
	2003/04	7,814	-12.17	8,897	9.39	9,732
	2004/05	7,939	-12.76	9,100	9.87	9,998
	2005/06	8,050	-13.53	9,310	10.50	10,288
	2006/07	8,179	-14.10	9,522	11.13	10,582
	2007/08	8,297	-14.82	9,741	11.71	10,882
	2008/09	8,432	-15.33	9,959	12.15	11,169
	2009/10	8,552	-16.00	10,181	12.89	11,493
2000/01-2009/10 AAGR	1.53			2.29		2.87
1991/92-2009/10 AAGR	1.35			2.15		2.75

SUMMER PEAK DEMAND

APRIL 1991 FORECAST



FLORIDA POWER CORPORATION SUMMER PEAK MW DEMAND

		YEAR	ACTUAL			
HISTORY:		1975	2,975			
		1976	3,223			
		1977	3,407			
		1978	3,521			
		1979	3,667			
		1980	3,995			
		1981	4,355			
		1982	4,086			
		1983	4,610			
		1984	4,163			
		1985	4,548			
		1986	4,644			
		1987	5,196			
		1988	5,309			
		1989	5,832			
		1990	5,946			
1975-1990 AAGR			4.72			
	YEAR	LOW	% DIFF	BASE	% DIFF	HIGH
FORECAST	1991	5,821	0.00	5,821	0.00	5,821
	1992	5,874	-3.32	6,076	1.50	6,167
	1993	6,052	-4.21	6,318	1.99	6,444
	1994	6,177	-4.97	6,500	2.54	6,665
	1995	6,346	-5.76	6,734	3.28	6,955
	1996	6,452	-6.44	6,896	3.89	7,164
	1997	6,551	-7.12	7,053	4.61	7,378
	1998	6,623	-8.05	7,203	5.40	7,592
	1999	6,707	-8.80	7,354	6.04	7,798
	2000	6,816	-9.49	7,531	6.77	8,041
1991-2000 AAGR		1.77		2.90		3.66
	2001	6,933	-10.15	7,716	7.32	8,281
	2002	7,043	-10.86	7,901	8.01	8,534
	2003	7,157	-11.50	8,087	8.72	8,792
	2004	7,262	-12.18	8,269	9.38	9,045
	2005	7,376	-12.76	8,455	9.86	9,289
	2006	7,472	-13.54	8,642	10.51	9,550
	2007	7,582	-14.10	8,827	11.14	9,810
	2008	7,678	-14.82	9,014	11.72	10,070
	2009	7,790	-15.34	9,201	12.15	10,319
	2010	7,825	-16.00	9,387	12.89	10,597
2001-2010 AAGR		1.44		2.20		2.78
1991-2010 AAGR		1.61		2.55		3.20

Appendix B:
FUEL COST FORECAST

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY LOW FORECAST (PER APRIL 8, 1991)

2.5 % RESID. OIL / HS COAL = 1.173 (1997)
DIST. / 2.5 % RESID. OIL = 2.005
1.0 % / 2.5 % RESID. OIL = 1.133
NEW GAS / 2.5 % RESID. OIL = 1.029

2.5 % RESID. OIL / HS COAL = 1.194 (2005)
DIST. / 2.5 % RESID. OIL = 2.195
1.0 % / 2.5 % RESID. OIL = 1.194
NEW GAS / 2.5 % RESID. OIL = 1.057

YEAR	1.0 % COAL (C/MBTU)	ESCL (%)	0.7 % COAL (C/MBTU)	ESCL (%)	1.5 % OR HIGHER COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELINE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	ORIMULSION (C/MBTU)	ESCL (%)
1991	190.90		203.10	0.0	168.00	0.0	206.40		376.19		222.20				288.10		171.00	0.6
1992	199.20	4.3	203.10	0.0	168.00	0.0	214.30	3.8	390.86	3.9	230.20	3.6	230.00	2.2	296.60	3.0	172.00	1.2
1993	198.00	-0.6	203.10	0.0	170.00	1.2	222.20	3.7	406.11	3.9	238.10	3.4	235.00	2.1	305.10	2.9	174.00	1.7
1994	200.00	1.0	203.10	0.0	172.00	1.2	230.20	3.6	421.94	4.2	246.00	3.3	240.00	2.1	313.60	2.8	177.00	2.3
1995	201.00	0.5	205.00	0.9	176.00	2.3	238.10	3.4	439.66	4.2	254.00	3.1	245.00	2.0	322.00	2.7	181.00	2.2
1996	202.00	0.5	207.00	1.0	180.00	2.3	238.10	0.0	458.13	4.2	269.80	3.0	250.00	2.0	330.50	2.6	185.00	2.7
1997	203.00	0.5	209.00	0.9	184.00	2.2	242.10	1.7	477.37	4.2	277.80	3.0	255.00	2.0	339.00	2.6	190.00	2.6
1998	204.00	0.5	210.90	0.9	188.00	2.1	246.00	1.6	497.42	4.2	285.70	2.8	260.00	2.0	347.50	2.5	195.00	2.6
1999	205.00	0.5	212.90	0.9	192.00	2.1	246.00	0.0	518.31	4.2	293.70	2.8	270.92	4.2	355.90	2.4	200.00	5.0
2000	206.00	0.5	214.80	0.9	200.00	4.2	256.33	4.2	540.08	4.2	306.04	4.2	282.30	4.2	372.90	4.8	210.00	4.2
2001	214.65	4.2	223.82	4.2	208.40	4.2	267.10	4.2	562.76	4.2	318.89	4.2	294.18	4.2	388.56	4.2	218.82	4.2
2002	223.67	4.2	233.22	4.2	217.15	4.2	278.32	4.2	586.40	4.2	332.28	4.2	306.51	4.2	404.88	4.2	228.01	4.2
2003	233.08	4.2	243.02	4.2	226.27	4.2	290.01	4.2	611.03	4.2	346.24	4.2	319.38	4.2	421.69	4.2	237.59	4.2
2004	242.85	4.2	253.22	4.2	235.78	4.2	302.19	4.2	636.69	4.2	360.78	4.2	332.80	4.2	439.61	4.2	247.57	4.2
2005	253.05	4.2	263.86	4.2	245.68	4.2	314.88	4.2	663.43	4.2	375.93	4.2	346.77	4.2	458.07	4.2	257.96	4.2
2006	263.68	4.2	274.94	4.2	256.00	4.2	328.10	4.2	691.29	4.2	391.72	4.2	361.34	4.2	477.31	4.2	268.80	4.2
2007	274.75	4.2	286.49	4.2	266.75	4.2	341.88	4.2	720.33	4.2	408.17	4.2	376.52	4.2	497.35	4.2	280.09	4.2
2008	286.29	4.2	298.52	4.2	277.95	4.2	356.24	4.2	750.58	4.2	425.32	4.2	392.33	4.2	518.24	4.2	291.85	4.2
2009	298.32	4.2	311.06	4.2	289.63	4.2	371.20	4.2	782.11	4.2	443.18	4.2	408.81	4.2	540.01	4.2	304.11	4.2
2010	310.85	4.2	324.12	4.2	301.79	4.2	386.79	4.2	814.96	4.2	461.79	4.2	425.98	4.2	562.69	4.2	316.88	4.2
2011	323.90	4.2	337.74	4.2	314.47	4.2	403.04	4.2	849.10	4.2	481.19	4.2	443.87	4.2	586.32	4.2	330.19	4.2
2012	337.50	4.2	351.92	4.2	327.67	4.2	419.97	4.2	884.85	4.2	501.40	4.2	462.51	4.2	610.95	4.2	344.06	4.2
2013	351.68	4.2	366.70	4.2	341.44	4.2	437.61	4.2	922.01	4.2	522.46	4.2	481.94	4.2	636.61	4.2	358.51	4.2
2014	366.45	4.2	382.10	4.2	355.78	4.2	455.99	4.2	960.74	4.2	544.40	4.2	502.18	4.2	663.35	4.2	373.57	4.2
2015	381.84	4.2	398.15	4.2	370.72	4.2	475.14	4.2	1001.09	4.2	567.27	4.2	523.27	4.2	691.21	4.2	389.26	4.2
2016	397.88	4.2	414.88	4.2	386.29	4.2	495.09	4.2	1043.13	4.2	591.09	4.2	545.25	4.2	720.24	4.2	405.60	4.2
2017	414.59	4.2	432.30	4.2	402.51	4.2	515.89	4.2	1086.95	4.2	615.92	4.2	568.15	4.2	750.49	4.2	422.64	4.2
2018	432.00	4.2	450.46	4.2	419.42	4.2	537.55	4.2	1132.60	4.2	641.79	4.2			782.01	4.2	440.39	4.2
2019	450.15	4.2	469.38	4.2	437.04	4.2			1180.17	4.2					814.85	4.2	458.89	4.2

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY MEDIUM FORECAST

(PER APRIL 8, 1991)

2.5 % RESID. OIL / HS COAL = 1.642 (1997)
DIST. / 2.5 % RESID. OIL = 1.639
1.0 % / 2.5 % RESID. OIL = 1.184
NEW GAS / 2.5 % RESID. OIL = 1.029

2.5 % RESID. OIL / HS COAL = 1.674 (2005)
DIST. / 2.5 % RESID. OIL = 1.636
1.0 % / 2.5 % RESID. OIL = 1.172
NEW GAS / 2.5 % RESID. OIL = 1.173

YEAR	1.0 % COAL (C/MBTU)	ESCL (%)	0.7 % COAL (C/MBTU)	ESCL (%)	1.5 % OR HIGHER COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELINE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	ORIMULSION (C/MBTU)	ESCL (%)
1991	190.90		204.60		172.00	0.0	269.80	0.0	434.50	5.0	317.50	0.0			355.90		200.00	2.0
1992	201.80	5.7	207.80	1.5	172.00	0.0	269.80	5.5	456.21	7.9	333.30	5.0			372.90	4.8	204.00	4.4
1993	206.00	2.1	210.70	1.5	179.00	4.1	285.70	5.5	492.41	8.8	365.10	9.5	285.00		406.80	9.1	213.00	3.8
1994	212.10	3.0	215.70	2.4	185.00	3.4	325.40	13.8	535.86	8.8	412.70	13.0	330.00	15.8	457.60	12.5	221.00	4.1
1995	214.40	1.1	221.50	2.7	192.00	3.8	349.20	7.3	564.83	5.4	444.40	7.7	360.00	9.1	542.40	6.7	241.73	5.1
1996	225.33	5.1	232.80	5.1	201.79	5.1	365.10	4.8	601.03	6.4	460.30	3.6	400.00	11.1	576.30	6.2	254.06	5.1
1997	236.83	5.1	244.67	5.1	212.08	5.1	388.90	6.5	637.24	6.0	482.10	5.9	440.00	10.0	610.20	5.9	267.02	5.1
1998	248.90	5.1	257.15	5.1	222.90	5.1	421.70	8.4	673.45	5.7	523.80	6.4	500.00	13.8	644.10	5.6	280.63	5.1
1999	261.60	5.1	270.26	5.1	234.27	5.1	436.50	3.5	716.90	8.5	539.70	3.0	540.00	8.0	711.90	10.5	294.95	5.1
2000	274.94	5.1	284.05	5.1	246.22	5.1	460.30	5.5	753.10	5.0	567.22	5.1	567.54	5.1	748.21	5.1	309.99	5.1
2001	288.96	5.1	298.53	5.1	258.77	5.1	483.78	5.1	791.51	5.1	596.15	5.1	596.48	5.1	786.37	5.1	325.80	5.1
2002	303.70	5.1	313.78	5.1	271.97	5.1	508.45	5.1	831.88	5.1	626.56	5.1	626.91	5.1	826.47	5.1	342.41	5.1
2003	319.19	5.1	329.78	5.1	285.84	5.1	534.38	5.1	874.30	5.1	658.51	5.1	658.88	5.1	868.62	5.1	359.88	5.1
2004	335.47	5.1	346.58	5.1	300.42	5.1	561.63	5.1	918.89	5.1	692.10	5.1	692.48	5.1	912.92	5.1	378.23	5.1
2005	352.58	5.1	364.25	5.1	315.74	5.1	590.28	5.1	965.75	5.1	727.39	5.1	727.80	5.1	959.48	5.1	397.52	5.1
2006	370.56	5.1	382.63	5.1	331.84	5.1	620.38	5.1	1015.01	5.1	764.49	5.1	764.91	5.1	1006.41	5.1	417.79	5.1
2007	389.46	5.1	402.35	5.1	348.77	5.1	652.02	5.1	1066.77	5.1	803.48	5.1	803.92	5.1	1059.84	5.1	439.10	5.1
2008	409.32	5.1	422.87	5.1	366.55	5.1	685.27	5.1	1121.18	5.1	844.46	5.1	844.93	5.1	1113.89	5.1	461.49	5.1
2009	430.19	5.1	444.44	5.1	385.25	5.1	720.22	5.1	1178.36	5.1	887.52	5.1	888.02	5.1	1170.70	5.1	485.03	5.1
2010	452.13	5.1	467.10	5.1	404.89	5.1	756.95	5.1	1238.45	5.1	932.79	5.1	933.31	5.1	1230.41	5.1	509.77	5.1
2011	475.19	5.1	490.93	5.1	425.54	5.1	795.56	5.1	1301.61	5.1	980.36	5.1	980.90	5.1	1293.16	5.1	535.76	5.1
2012	499.43	5.1	515.98	5.1	447.25	5.1	836.13	5.1	1368.00	5.1	1030.36	5.1	1030.93	5.1	1359.11	5.1	563.09	5.1
2013	524.90	5.1	542.28	5.1	470.06	5.1	878.77	5.1	1437.77	5.1	1082.91	5.1	1083.51	5.1	1428.42	5.1	591.81	5.1
2014	551.67	5.1	569.94	5.1	494.03	5.1	923.59	5.1	1511.09	5.1	1136.13	5.1	1136.77	5.1	1501.27	5.1	621.99	5.1
2015	579.80	5.1	599.00	5.1	519.22	5.1	970.69	5.1	1588.16	5.1	1196.18	5.1	1196.84	5.1	1577.84	5.1	653.71	5.1
2016	609.37	5.1	629.55	5.1	545.71	5.1	1020.20	5.1	1669.15	5.1	1257.18	5.1	1257.88	5.1	1658.31	5.1	687.05	5.1
2017	640.45	5.1	661.66	5.1	573.54	5.1	1072.23	5.1	1754.28	5.1	1321.30	5.1	1322.03	5.1	1742.88	5.1	722.09	5.1
2018	673.11	5.1	695.40	5.1	602.79	5.1	1126.91	5.1	1843.75	5.1	1388.69	5.1	1389.46	5.1	1831.77	5.1	758.91	5.1
2019	707.44	5.1	730.87	5.1	633.53	5.1	1184.38	5.1	1937.78	5.1								

FUEL COST PROJECTIONS FOR GENERATION FACILITY STUDY HIGH FORECAST

(PER APRIL 8, 1991)

2.5 % RESID. OIL / HS COAL = 1.574 (1997)
 DIST. / 2.5 % RESID. OIL = 1.597
 1.0 % / 2.5 % RESID. OIL = 1.167
 NEW GAS / 2.5 % RESID. OIL = 1.340

2.5 % RESID. OIL / HS COAL = 1.574 (2009)
 DIST. / 2.5 % RESID. OIL = 1.597
 1.0 % / 2.5 % RESID. OIL = 1.167
 NEW GAS / 2.5 % RESID. OIL = 1.340

YEAR	1.0 % COAL (C/MBTU)	ESCL (%)	0.7 % COAL (C/MBTU)	ESCL (%)	1.5 % OR HIGHER COAL (C/MBTU)	ESCL (%)	2.5 % RESID OIL (C/MBTU)	ESCL (%)	DIST. OIL (C/MBTU)	ESCL (%)	1.0 % RESID OIL (C/MBTU)	ESCL (%)	NEW PIPELINE GAS (C/MBTU)	ESCL (%)	0.3 % RESID OIL (C/MBTU)	ESCL (%)	ORIMULSION (C/MBTU)	ESCL (%)
1991	204.10		212.60		216.70		285.70		506.90		317.50				440.70		250.00	
1992	224.50	10.0	234.10	10.1	216.70	0.0	317.50	11.1	567.60	10.0	349.20	10.0			491.50	11.5	265.00	6.0
1993	241.80	7.7	252.00	7.8	229.20	5.8	349.20	10.0	579.30	3.9	386.00	10.5	525.00	10.5	542.40	10.4	281.00	6.0
1994	266.70	10.3	278.20	10.4	250.00	9.1	386.00	10.5	637.20	10.0	428.80	11.0			576.30	6.2	298.00	6.0
1995	284.04	8.5	296.28	8.5	270.80	8.3	412.70	6.9	687.90	8.0	476.20	11.1	580.00	10.5	627.10	8.8	316.00	6.0
1996	302.50	6.5	315.54	6.5	288.40	6.5	476.20	15.4	760.30	10.5	555.50	16.7	638.03	6.5	728.80	16.2	380.00	20.3
1997	322.18	6.5	336.05	6.5	307.15	6.5	507.15	6.5	809.72	6.5	591.61	6.5	679.47	6.5	776.17	6.5	455.00	19.7
1998	343.10	6.5	357.89	6.5	327.11	6.5	540.12	6.5	862.35	6.5	630.08	6.5	723.64	6.5	826.82	6.5	530.00	16.5
1999	365.40	6.5	381.16	6.5	348.38	6.5	575.23	6.5	916.40	6.5	671.02	6.5	770.67	6.5	880.35	6.5	580.00	5.7
2000	389.15	6.5	405.93	6.5	371.02	6.5	612.62	6.5	978.10	6.5	714.63	6.5	820.77	6.5	937.56	6.5	600.00	7.1
2001	414.45	6.5	432.32	6.5	395.14	6.5	652.44	6.5	1041.68	6.5	761.08	6.5	874.12	6.5	996.52	6.5	639.00	6.5
2002	441.39	6.5	460.42	6.5	420.82	6.5	694.84	6.5	1109.39	6.5	810.55	6.5	930.93	6.5	1063.42	6.5	680.54	6.5
2003	470.08	6.5	490.35	6.5	448.17	6.5	740.01	6.5	1181.50	6.5	863.24	6.5	991.44	6.5	1132.55	6.5	724.77	6.5
2004	500.63	6.5	522.22	6.5	477.30	6.5	788.11	6.5	1258.29	6.5	919.35	6.5	1055.89	6.5	1206.18	6.5	771.88	6.5
2005	533.17	6.5	556.18	6.5	508.33	6.5	839.34	6.5	1340.08	6.5	979.11	6.5	1124.52	6.5	1284.58	6.5	822.05	6.5
2006	567.83	6.5	582.31	6.5	541.37	6.5	893.69	6.5	1427.19	6.5	1042.75	6.5	1197.61	6.5	1368.06	6.5	875.49	6.5
2007	604.74	6.5	630.82	6.5	576.56	6.5	952.00	6.5	1519.95	6.5	1110.53	6.5	1275.46	6.5	1456.98	6.5	932.39	6.5
2008	644.05	6.5	671.82	6.5	614.04	6.5	1013.88	6.5	1610.75	6.5	1182.71	6.5	1358.38	6.5	1551.89	6.5	993.00	6.5
2009	685.91	6.5	715.49	6.5	653.95	6.5	1079.78	6.5	1723.97	6.5	1259.59	6.5	1446.66	6.5	1652.54	6.5	1057.54	6.5
2010	730.49	6.5	761.99	6.5	696.45	6.5	1149.96	6.5	1836.03	6.5	1341.46	6.5	1540.69	6.5	1759.96	6.5	1126.28	6.5
2011	777.98	6.5	811.52	6.5	741.72	6.5	1224.71	6.5	1955.37	6.5	1428.66	6.5	1640.83	6.5	1874.36	6.5	1199.49	6.5
2012	828.54	6.5	864.27	6.5	789.94	6.5	1304.32	6.5	2082.47	6.5	1521.52	6.5	1747.49	6.5	1996.19	6.5	1277.46	6.5
2013	882.40	6.5	920.45	6.5	841.28	6.5	1389.10	6.5	2217.83	6.5	1620.42	6.5	1861.08	6.5	2125.94	6.5	1360.49	6.5
2014	939.76	6.5	980.28	6.5	895.97	6.5	1479.39	6.5	2361.99	6.5	1725.75	6.5	1982.05	6.5	2264.13	6.5	1448.92	6.5
2015	1000.84	6.5	1044.00	6.5	954.20	6.5	1575.55	6.5	2515.52	6.5	1837.92	6.5	2110.88	6.5	2411.30	6.5	1543.10	6.5
2016	1065.89	6.5	1111.86	6.5	1016.23	6.5	1677.96	6.5	2653.16	6.5	1957.38	6.5	2248.09	6.5	2568.03	6.5	1643.41	6.5
2017	1135.18	6.5	1184.13	6.5	1082.28	6.5	1787.03	6.5	2838.62	6.5	2084.61	6.5	2394.21	6.5	2734.95	6.5	1750.23	6.5
2018	1208.96	6.5	1261.09	6.5	1152.63	6.5	1903.18	6.5	3036.13	6.5	2220.11	6.5	2549.83	6.5	2912.73	6.5	1863.99	6.5
2019	1287.55	6.5	1343.07	6.5	1227.55	6.5	2026.89	6.5	3236.13	6.5	2364.42	6.5	2715.57	6.5	3102.05	6.5	1985.15	6.5

Appendix C:
INTERCHANGE CONTRACTS LIST

Florida Power Corporation
INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

1. FLORIDA POWER & LIGHT

Commence: 7/8/77 and amended 3/10/81
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: 1 year prior notice - end of contract period
Schedules: A, B, C, X, & F (F as a special contract)

2. FORT PIERCE UTILITIES AUTHORITY

Commence: 1/1/85
Term: Continuous until cancelled
Cancel: 1 year notice anytime provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedule: A, B, C, D, F, X

3. CITY OF GAINESVILLE

Commence: 12/1/79
Term: 5 years
Renewal: 2 year periods - automatic
Cancel: 2 years prior notice - end of contract period
Schedules: A, B, C, D, X

4. CITY OF HOMESTEAD

Commence: 12/19/77
Term: Continuous until cancelled
Cancel: 1 year notice anytime, provided the term of contract shall not be for a period less than the term of any service schedule commitment.
Schedule: A, B, C, D, F, X

Florida Power Corporation
INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

5. JACKSONVILLE ELECTRIC AUTHORITY

Commence: 5/20/80
Term: Continuous until cancelled
Cancel: 1 year notice anytime, provided that the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, X

6. CITY OF KISSIMMEE

Commence: 12/1/81
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: 1 year prior notice - end of period, or anytime by mutual agreement, provided that the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, X

7. CITY OF LAKELAND

Commence: 11/3/80
Term: 5 years
Renewal: 6 month periods - automatic
Cancel: 6 month prior notice - end of contract period
Schedules: A, B, C, D, X

8. LAKE WORTH UTILITIES AUTHORITY

Commence: 1/1/85
Term: Continuous until cancelled
Cancel: 1 year notice anytime, provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedule: A, B, C, D, F, X

Florida Power Corporation
**INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990**

9. CITY OF NEW SMYRNA BEACH

Commence: 11/1/85
Term: Continuous until cancelled
Cancel: 1 year notice anytime provided the term of the contract shall not be for a period of less than the term of any service schedule commitment.
Schedule: A, B, C, D, F, X

10. ORLANDO UTILITIES COMMISSION

Commence: 7/2/79
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: 1 year prior notice - end of contract period
Schedules: A, B, C, D, F, J

11. SEBRING UTILITIES COMMISSION

Commence: 2/1/80
Term: 5 years.
Renewal: 2 year periods - automatic.
Cancel: 2 year prior notice - end of period or anytime by mutual agreement between parties, but not before a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, H, I

12. SEMINOLE ELECTRIC COOPERATIVE, INC.

Commence: 8/1/83
Term: 5 years - ending 12/31/88.
Renewal: 1 year periods - automatic.
Cancel: 1 year prior notice
Schedules: A, B, C, D, G, H, X

Florida Power Corporation

INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

13. SOUTHEASTERN POWER ADMINISTRATION

Effective: 8/20/57
Term: 10 years
Renewal: 5 year periods - automatic
Cancel: 3 years prior notice - end of contract period
Schedules: Wholesale Power Rate Schedules JW-1 Rev. & JW-2 Rev.

14. SOUTHERN COMPANY SERVICES

Commence: 01/01/89
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: 1 year notice - end of any period
Schedules: A - Emergency Assistance
C - Economy Interchange
EP - Economic Energy Participation
E - Long Term Power
F - Short Term Power - Optional

15. CITY OF TALLAHASSEE

Commence: 5/1/83
Term: 5 years
Renewal: 2 year periods - automatic
Cancel: 1 years prior notice - end of period, or anytime by mutual agreement, provided that the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, H, I, X

16. TAMPA ELECTRIC COMPANY

Commence: 7/21/77
Term: 5 years
Renewal: 1 year period - automatic
Cancel: 1 year prior notice - end of contract period
Schedules: A, B, C, J,X

Florida Power Corporation
INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

17. CITY OF VERO BEACH

Commence: 12/1/81
Term: Continuous until cancelled
Cancel: One year written notice anytime provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, X

18. CITY OF ST. CLOUD

Commence: 12/1/81
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: 1 years prior notice - end of period, or anytime by mutual agreement, provided that the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, H, I, X

19. CITY OF STARKE

Commence: 9/1/85
Term: 1 year
Renewal: Continuous
Cancel: One year written notice anytime provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, X

20. FLORIDA MUNICIPAL POWER AGENCY

Commence: 5/1/86
Term: 5 years
Renewal: 1 year periods - automatic
Cancel: One year written notice anytime provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, H, X

Florida Power Corporation
INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

21. CITY OF KEY WEST

Commence: 4/1/87
Term: Continuous until cancelled.
Cancel: One year written notice anytime provided the term of the contract shall not be for a period less than the term of any service schedule commitment.
Schedules: A, B, C, D, F, X

22. DUKE POWER COMPANY

Commence: 2/1/89
Term: Not specified.
Cancel: 90 days from notice.
Schedules: EP

23. CAJUN

Commence: 9/1/89
Term: Not specified.
Cancel: 90 days
Schedules: EP

24. ENTERGY

Commence: 9/1/89
Term: Not specified.
Cancel: 90 days
Schedules: EP

25. REEDY CREEK IMPROVEMENT DISTRICT

Commence: 9/15/89
Term: 5 years.
Renewal: 1 year periods - automatic.
Cancel: 1 year prior notice - end of contract period.

Florida Power Corporation
INTERCHANGE AGREEMENTS
AS OF DECEMBER 31, 1990

SCHEDULES:

- A - Emergency Interchange Service
- B - Short Term Firm Interchange Service
- C - Economy Interchange Service
- D - Firm Interchange Service
- E - Long Term Power
- EP- Economy Participation
- F - Assured Capacity and Energy Interchange Service
- F - (Southern) Short Term Power - Optional
- G - Backup Interchange Service
- H - Reserve Interchange Service
- I - Regulation Interchange Service
- J - Negotiated Interchange Service
- X - Extended Economy Interchange Service

Appendix D:

GENERATION TECHNOLOGIES

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Pulverized Coal SIZE: 700 MW

DESCRIPTION:

Reference design, subcritical
Average for two units
Eastern coals, 3% sulfur, 10% ash
Natural draft cooling towers
Electrostatic precipitators
Wet limestone scrubbers (95% removal)
Landfill disposal of solid wastes
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 700 MW
Summer: 679 MW
Winter: 700 MW

CAPITAL COST: \$1,112/kw

FIXED O&M: \$14.89/kw/yr

VARIABLE O&M: \$4.58/Mwh

HEAT RATE:

Full Load (Summer): 9,800 Btu/kwh
Half Load (Summer): 10,400 Btu/kwh
Full Load (Winter): 9,500 Btu/kwh
Half Load (Winter): 10,100 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 8%
Forced Outage Rate: 5%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Added costs associated with FGD upgrades
Increased availability projection
Accounted for summer de-rating due to cooling temps.

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Pulverized Coal SIZE: 450 MW

DESCRIPTION:

Reference design, subcritical
Average for two units
Eastern coals, 3% sulfur, 10% ash
Natural draft cooling towers
Electrostatic precipitators
Wet limestone scrubbers (95% removal)
Landfill disposal of solid wastes
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 450 MW
Summer: 437 MW
Winter: 450 MW

CAPITAL COST: \$1,254/kw

FIXED O&M: \$21.77/kw/yr

VARIABLE O&M: \$4.58/Mwh

HEAT RATE:

Full Load (Summer): 9,800 Btu/kwh
Half Load (Summer): 10,400 Btu/kwh
Full Load (Winter): 9,500 Btu/kwh
Half Load (Winter): 10,100 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 8%
Forced Outage Rate: 5%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Added costs associated with FGD upgrades
Increased availability projection
Accounted for summer de-rating due to cooling temps.
Adjusted rating to 450 MW

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Pulverized Coal

SIZE: 450 MW

DESCRIPTION:

Reference design, subcritical
Average for two units
Eastern coals, 3% sulfur, 10% ash
Natural draft cooling towers
Electrostatic precipitators
Wet limestone scrubbers (95% removal)
Landfill disposal of solid wastes
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 450 MW
Summer: 437 MW
Winter: 450 MW

CAPITAL COST: \$1,254/kw

FIXED O&M: \$21.77/kw/YR

VARIABLE O&M: \$4.58/Mwh

HEAT RATE:

Full Load (Summer): 9,800 Btu/kwh
Half Load (Summer): 10,400 Btu/kwh
Full Load (Winter): 9,500 Btu/kwh
Half Load (Winter): 10,100 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 8%
Forced Outage Rate: 5%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Added costs associated with FGD upgrades
Increased availability projection
Accounted for summer de-rating due to cooling temps.
Adjusted rating to 450 MW

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Atmospheric Fluidized Bed

SIZE: 150 MW

DESCRIPTION:

Circulating bed design, subcritical
Average for two units
Eastern coals, 3% sulfur, 10% ash
Mechanical draft cooling towers
Baghouse particulate removal
Landfill disposal of solid wastes
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 150 MW
Summer: 146 MW
Winter: 150 MW

CAPITAL COST: \$1,615/kw

FIXED O&M: \$40.92/kw/yr

VARIABLE O&M: \$5.25/Mwh

HEAT RATE:

Full Load (Summer): 9,800 Btu/kwh
Half Load (Summer): 10,400 Btu/kwh
Full Load (Winter): 9,500 Btu/kwh
Half Load (Winter): 10,100 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 10%
Forced Outage Rate: 7%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Increased availability projection
Accounted for summer de-rating due to cooling temps.
Lowered F.O.R. based on performance at TNP-1

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: IGCC

SIZE: 530 MW

DESCRIPTION:

Average for two units
Advanced Technology CT's (2x1)
Texaco process with spare gasifier (1 for 4)
Including air separation plant
Seasoned performance
NOx control by steam injection
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 530 MW
Summer: 500 MW
Winter: 580 MW

CAPITAL COST: \$1423/kw

FIXED O&M: \$24.90/kw/yr

VARIABLE O&M: \$3.43/Mwh

HEAT RATE:

Full Load (Summer): 9,010 Btu/kwh
Half Load (Summer): 9,911 Btu/kwh
Full Load (Winter): 8,920 Btu/kwh
Half Load (Winter): 9,851 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 5%
Forced Outage Rate: 10%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Allowance for increased output from CT

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: IGCC

SIZE: 265 MW

DESCRIPTION:

Average for two units
Advanced Technology CT's (1x1)
Texaco process with spare gasifier (1 for 2)
Including air separation plant
Seasoned performance
NOx control by steam injection
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 265 MW
Summer: 250 MW
Winter: 290 MW

CAPITAL COST: \$1473/kw

FIXED O&M: \$27.00/kw/yr

VARIABLE O&M: \$3.75/Mwh

HEAT RATE:

Full Load (Summer): 9,010 Btu/kwh
Half Load (Summer): 11,263 Btu/kwh
Full Load (Winter): 8,920 Btu/kwh
Half Load (Winter): 11,150 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 5%
Forced Outage Rate: 10%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Allowance for increased output from CT
New case; base on advanced CT (1x1)

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: IGCC (Orimulsion) SIZE: 593 MW

DESCRIPTION:

Based on preliminary conceptual study with TEXACO
Stand alone unit
Advanced Technology CT's (2x1)
Texaco process with three gasifiers (40% capacity each)
Air separation plant owned and operated by others
New unit performance
NOx control by nitrogen injection
Located at non-specific site
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING (Gross/Net):

Nominal: 593/537 MW
Summer: 570/516 MW
Winter: 593/537 MW

CAPITAL COST: \$917/kw (based on nominal gross rating)
\$1012/kw (based on nominal net rating)

FIXED O&M: \$27.70/kw/yr (based on nominal gross rating)
\$30.59/kw/yr (based on nominal net rating)

VARIABLE O&M: \$3.22/Mwh (based on nominal gross rating)
\$3.56/Mwh (based on nominal net rating)

HEAT RATE (Net):

Full Load (Summer): 8,044 Btu/kwh
Half Load (Summer): 8,850 Btu/kwh
Full Load (Winter): 8,080 Btu/kwh
Half Load (Winter): 8,890 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 5%
Forced Outage Rate: 6% (4% with backup fuel)

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars
Allowance for increased output from CT
New case; conceptual basis, reflective of current work
Air separation unit is interruptible (56 MW nominal)
Non-typical performance curves apply (break point @ 59F)

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Combined Cycle
(Gas)

SIZE: 225 MW

DESCRIPTION:

Average for two units
Advanced Technology
Seasoned performance
Natural gas fired
NOx control by steam injection
Selective catalytic reduction
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 225 MW
Summer: 200 MW
Winter: 235 MW

CAPITAL COST: \$599/kw

FIXED O&M: \$5.49/kw/yr

VARIABLE O&M: \$2.29/Mwh

HEAT RATE:

Full Load (Summer): 8,000 Btu/kwh
Half Load (Summer): 9,700 Btu/kwh
Full Load (Winter): 7,920 Btu/kwh
Half Load (Winter): 9,600 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 5%
Forced Outage Rate: 4%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:
Escalated to Jan. 1991 dollars

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Combined Cycle SIZE: 225 MW
(Distillate)

DESCRIPTION:

Average for two units
Advanced Technology
Seasoned performance
Oil fired
NOx control by steam injection
Selective catalytic reduction
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:

Nominal: 225 MW
Summer: 200 MW
Winter: 235 MW

CAPITAL COST: \$599/kw

FIXED O&M: \$5.49/kw/yr

VARIABLE O&M: \$2.29/Mwh

HEAT RATE:

Full Load (Summer): 7,825 Btu/kwh
Half Load (Summer): 9,500 Btu/kwh
Full Load (Winter): 7,747 Btu/kwh
Half Load (Winter): 9,405 Btu/kwh

AVAILABILITY:

Scheduled Maintenance: 5%
Forced Outage Rate: 5%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:

Escalated to Jan. 1991 dollars

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Combustion Turbine SIZE: 150 MW
(Natural Gas)

DESCRIPTION:
Average for two units
Advanced Technology
Seasoned performance
Gas fired
NOx control by water injection
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:
Nominal: 150 MW
Summer: 135 MW
Winter: 165 MW

CAPITAL COST: \$370/kw

FIXED O&M: \$6.18/kw/yr

VARIABLE O&M: \$1.83/Mwh

HEAT RATE:
Full Load (Summer): 12,489 Btu/kwh
Half Load (Summer): 14,433 Btu/kwh
Full Load (Winter): 11,591 Btu/kwh
Half Load (Winter): 13,395 Btu/kwh

AVAILABILITY:
Scheduled Maintenance: 5%
Forced Outage Rate: 2%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:
Escalated to Jan. 1991 dollars

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Combustion Turbine (Natural Gas) SIZE: 40 MW

DESCRIPTION:
Average for multiple units
LM 6000
Seasoned performance
Gas fired
NOx control by water injection
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:
Nominal: 40 MW
Summer: 37 MW
Winter: 40 MW

CAPITAL COST: \$444/kw

FIXED O&M: \$7.50/kw/yr

VARIABLE O&M: \$2.50/Mwh

HEAT RATE:
Full Load (Summer): 9,638 Btu/kwh
Half Load (Summer): 12,356 Btu/kwh
Full Load (Winter): 9,159 Btu/kwh
Half Load (Winter): 11,228 Btu/kwh

AVAILABILITY:
Scheduled Maintenance: 2%
Forced Outage Rate: 3%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:
Escalated to Jan. 1991 dollars
New technology option
Based on estimates from Stewart & Stevenson and ESI

GENERATION TECHNOLOGY INPUT
TO
1991 RESOURCE STUDY

TECHNOLOGY: Combustion Turbine SIZE: 150 MW
(Distillate)

DESCRIPTION:
Average for two units
Advanced Technology
Seasoned performance
Oil fired
NOx control by water injection
Excluding land and AFUDC
January, 1991 dollars

CAPACITY RATING:
Nominal: 150 MW
Summer: 135 MW
Winter: 165 MW

CAPITAL COST: \$370/kw

FIXED O&M: \$6.18/kw/yr

VARIABLE O&M: \$1.83/Mwh

HEAT RATE:
Full Load (Summer): 11,926 Btu/kwh
Half Load (Summer): 13,782 Btu/kwh
Full Load (Winter): 11,069 Btu/kwh
Half Load (Winter): 12,791 Btu/kwh

AVAILABILITY:
Scheduled Maintenance: 5%
Forced Outage Rate: 4%

SIGNIFICANT ADJUSTMENTS TO 1990 DATABASE:
Escalated to Jan. 1991 dollars

Appendix E:
DESCRIPTIONS OF 10 ALTERNATIVES

Alternative One

Large Pulverized Coal

Winter Capacity (MW)

800

600

400

200

0

1992

1993

1994

1995

1996

1997

1998

1999

2000

2001



Combustion
Turbine



Tie
Line



Pulverized
Coal

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Integrated Resource Study
Docket No. 910759-EI

Alternative Two

Small Pulverized Coal

Winter Capacity (MW)

800

600

400

200

0

1992

1993

1994

1995

1996

1997

1998

1999

2000

2001



Combustion
Turbine



Tie
Line



Pulverized
Coal

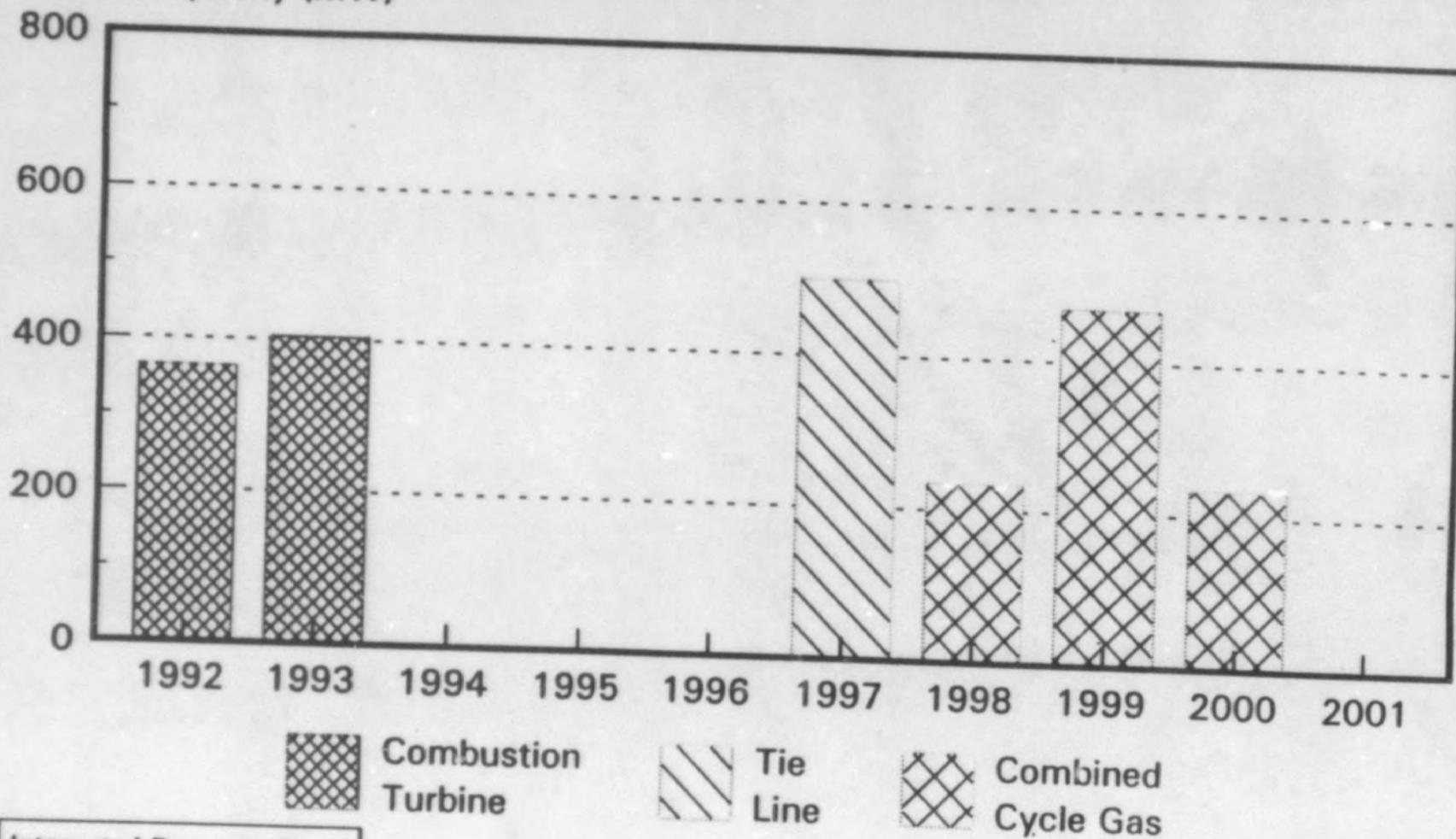
Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Three

Combined Cycle on Gas

Winter Capacity (MW)



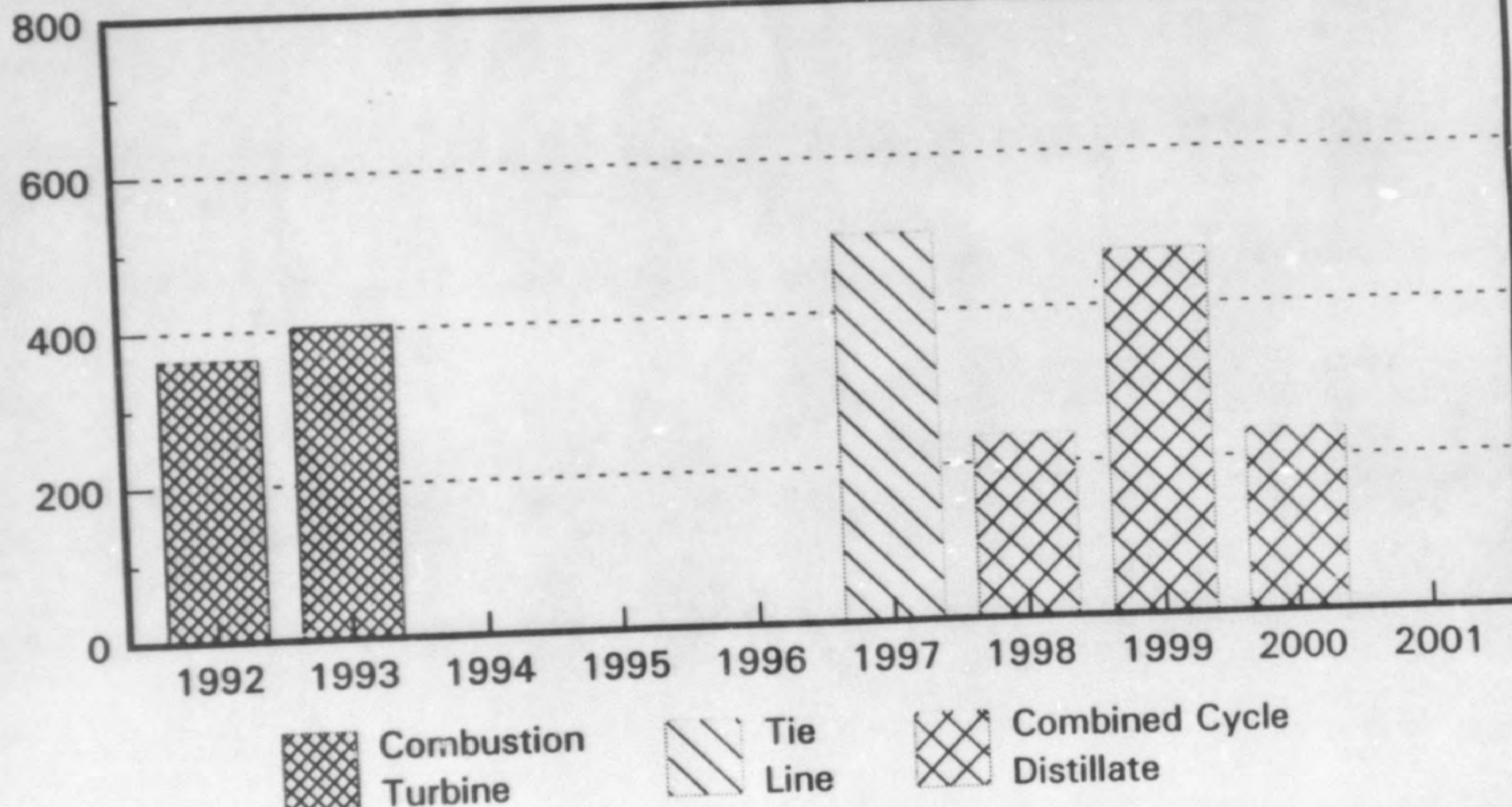
Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Four

Combined Cycle on Distillate

Winter Capacity (MW)



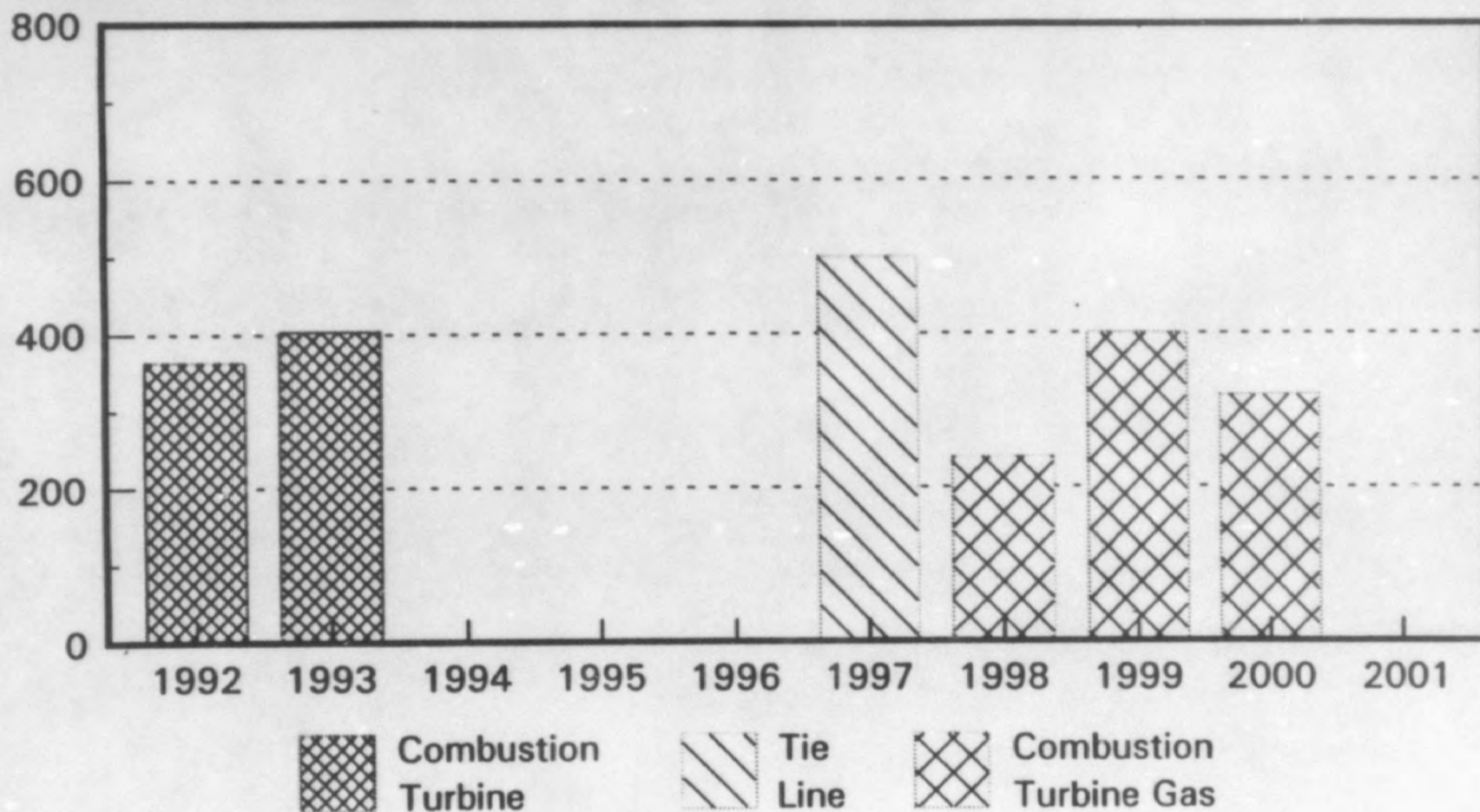
Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Five

Combustion Turbines on Gas

Winter Capacity (MW)

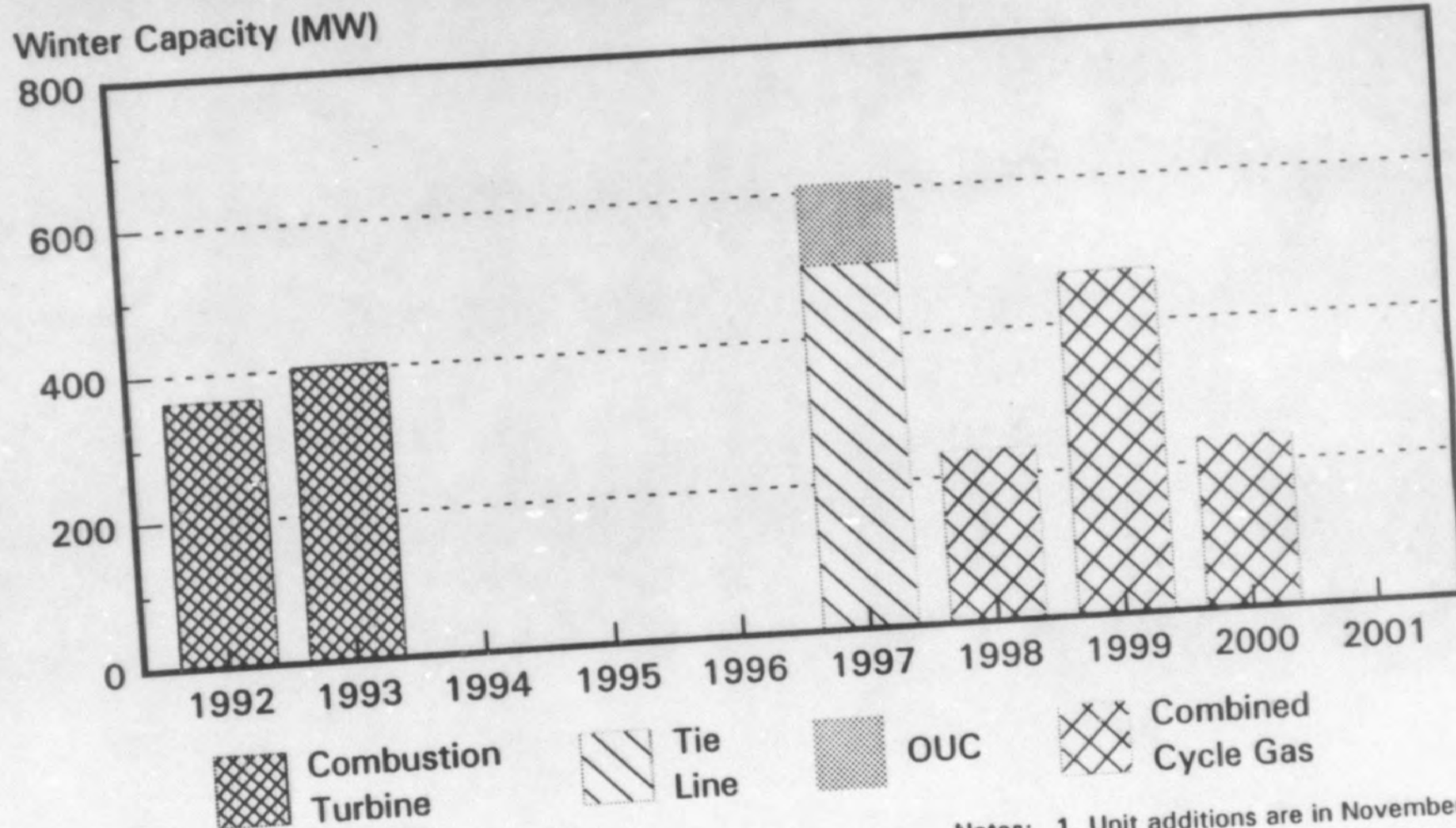


Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Six

OUC Purchase With Combined Cycles on Gas



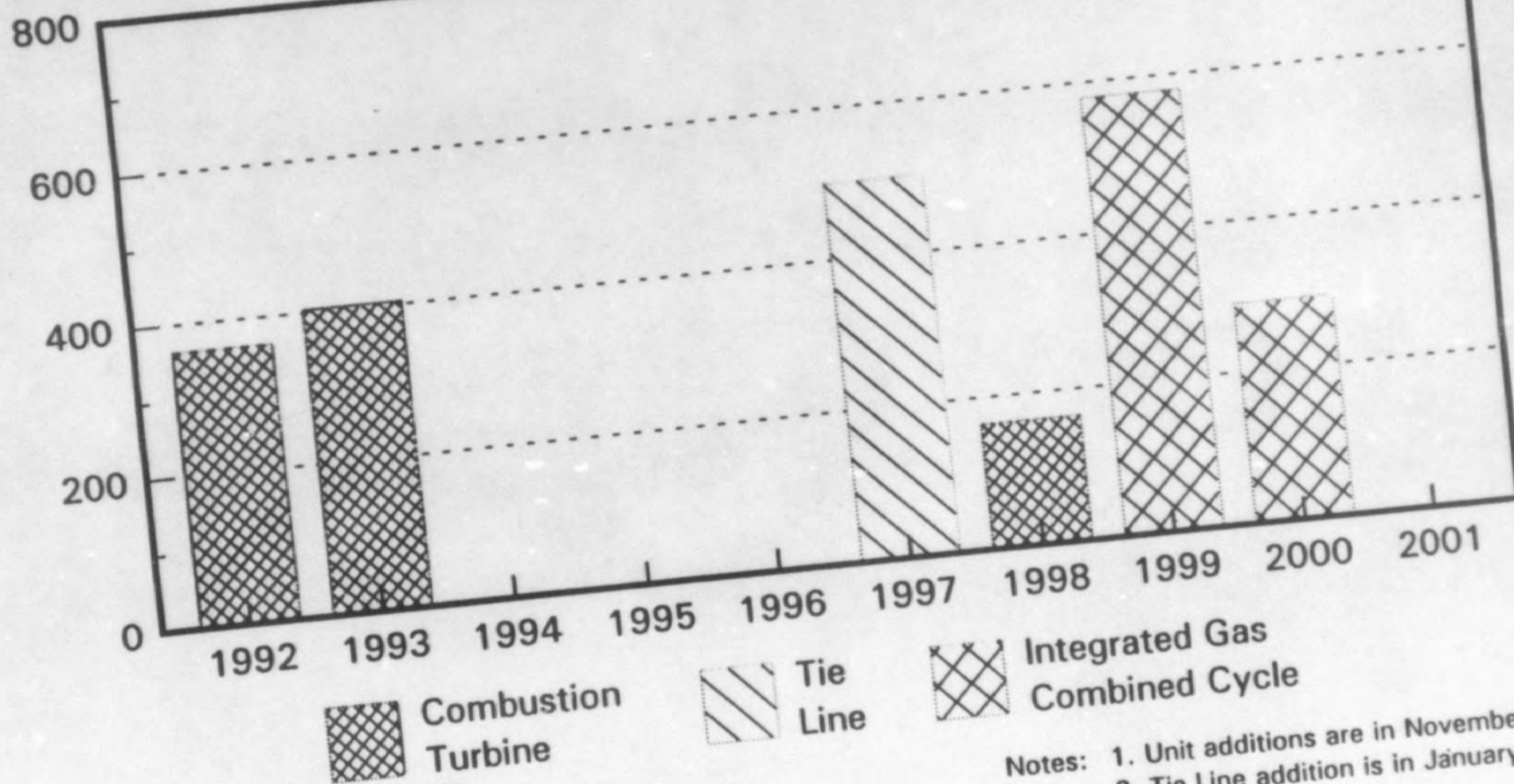
Integrated Resource Study
Docket No. 910759-EI

- Notes:
1. Unit additions are in November
 2. Tie Line addition is in January
 3. OUC addition is in January

Alternative Seven

Integrated Gasification Combined Cycle

Winter Capacity (MW)



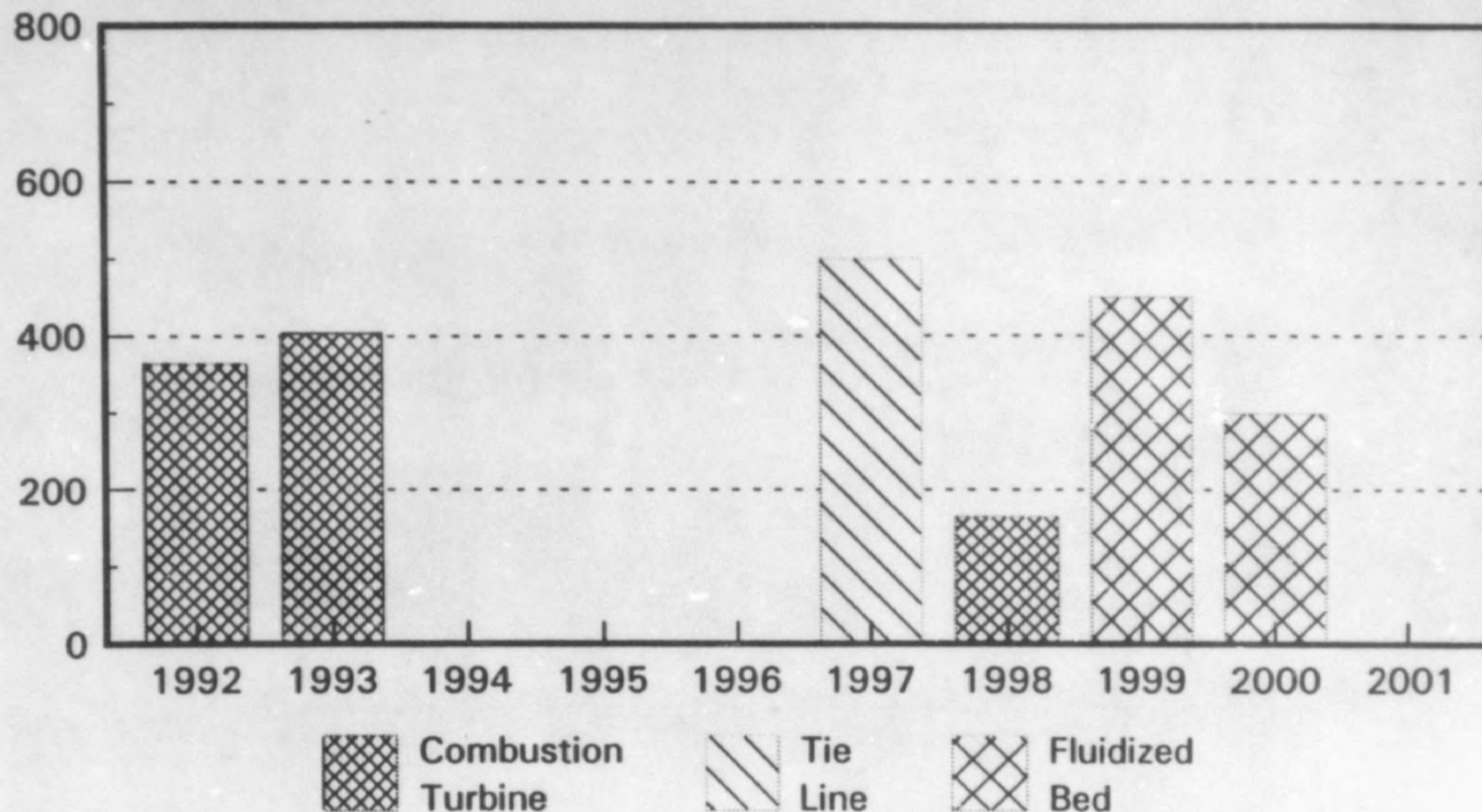
Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Eight

Fluidized Bed

Winter Capacity (MW)



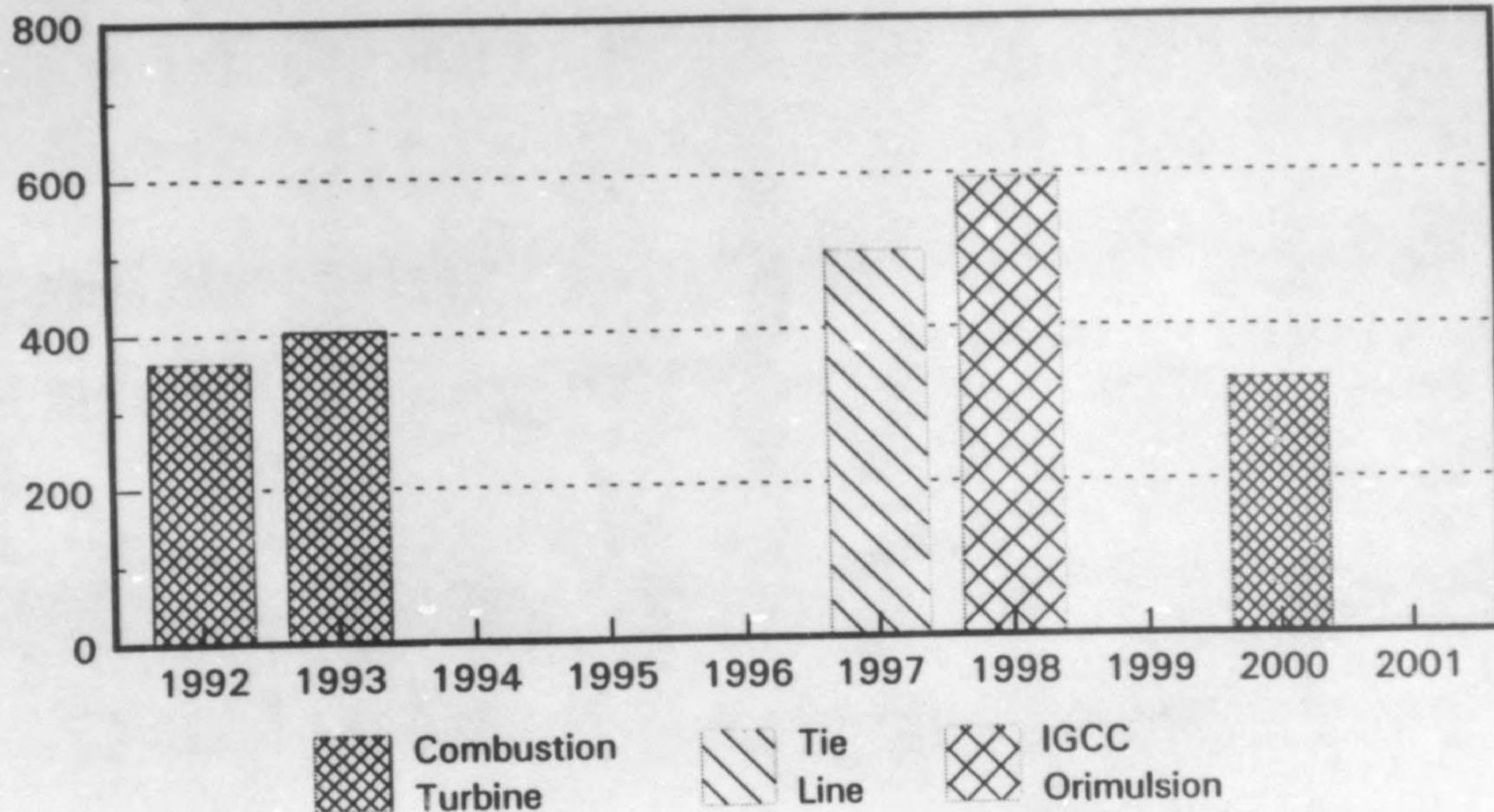
Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Nine

IGCC on Orimulsion

Winter Capacity (MW)



Integrated Resource Study
Docket No. 910759-EI

Notes: 1. Unit additions are in November
2. Tie Line addition is in January

Alternative Ten

Cajun UPS Purchase

Winter Capacity (MW)

800

600

400

200

0

1992

1993

1994

1995

1996

1997

1998

1999

2000

2001



Combustion
Turbine



Tie
Line



UPS



Combined
Cycle Gas



Combustion
Turbine Gas

Integrated Resource Study
Docket No. 910759-EI

- Notes:
1. Unit additions are in November
 2. Tie Line addition is in January
 4. Cajun UPS begins in January

Summary **ALTERNATIVE-1** **LARGE PULVERIZED COAL**

DESCRIPTION

1998: 2-165 MW COMBUSTION TURBINES ON DISTILLATE
 1999: 1-700 MW PULVERIZED COAL UNIT

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL

SO2 EMISSION TONNAGE:

2000: 120,136
 2001: 124,061

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	46.39%	OIL	14.99%	SOUTHERN	6.06%
NUCLEAR	11.76%	DISTILLATE	2.88%	QF	15.07%
GAS	0.41%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	29.86%	OIL	17.60%	SOUTHERN	4.02%
NUCLEAR	7.63%	DISTILLATE	25.91%	QF	9.49%
GAS	0.40%	PURCHASE	5.09%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
 \$17,972,691,000

RISK ANALYSIS:

THERE IS A 20% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS OCCURS DURING THE HIGH FUEL SCENARIOS.

ADVANTAGES:

1. USES EXISTING AND PROVEN TECHNOLOGY.
2. FUEL SUPPLY SECURITY.

DISADVANTAGES:

1. HIGH CAPITAL COST.
2. LONG CONSTRUCTION LEAD TIME.
3. CAPACITY ADDITION MISMATCH TO ANNUAL LOAD GROWTH.

Summary
ALTERNATIVE-2
SMALL PULVERIZED COAL

DESCRIPTION

1998: 2-165 MW COMBUSTION TURBINES ON DISTILLATE
 1999: 1-450 MW PULVERIZED COAL UNIT
 2000: 1-165 MW COMBUSTION TURBINE ON DISTILLATE

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL.
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL.

SO2 EMISSION TONNAGE: 2000: 126,613
 2001: 130,966

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL. (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	43.42%	OIL	16.46%	SOUTHERN	6.39%
NUCLEAR	11.76%	DISTILLATE	4.01%	QF	15.07%
GAS	0.45%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	27.61%	OIL	17.75%	SOUTHERN	4.05%
NUCLEAR	7.69%	DISTILLATE	27.80%	QF	9.57%
GAS	0.40%	PURCHASE	5.13%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$18,043,001,000

RISK ANALYSIS:

THERE IS A 5% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS OCCURS DURING HIGH FUEL, LOW DEMAND AND ENERGY SCENARIOS.

ADVANTAGES:

1. USES EXISTING AND PROVEN TECHNOLOGY.
2. FUEL SUPPLY SECURITY.
3. BETTER MATCH OF CAPACITY TO LOAD THAN ALTERNATIVE-1. (700 MW PC)

DISADVANTAGES:

1. HIGH CAPITAL COST.
2. LONG CONSTRUCTION LEAD TIME.

Summary **ALTERNATIVE-3** **COMBINED CYCLE ON GAS**

DESCRIPTION

1998: 1-235 MW COMBINED CYCLE ON GAS
 1999: 2-235 MW COMBINED CYCLES ON GAS
 2000: 1-235 MW COMBINED CYCLE ON GAS

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL

SO2 EMISSION TONNAGE: 2000: 123,332
 2001: 122,122

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS)
2. MUST RUN COMBINED CYCLE UNITS.

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	36.62%	OIL	14.34%	SOUTHERN	6.99%
NUCLEAR	11.76%	DISTILLATE	1.81%	QF	15.07%
GAS	10.97%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	23.05%	OIL	17.76%	SOUTHERN	4.05%
NUCLEAR	7.70%	DISTILLATE	22.80%	QF	9.57%
GAS	9.93%	PURCHASE	5.14%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
 \$17,704,108,000

RISK ANALYSIS:

THIS ALTERNATIVE IS USED AS THE BASE CASE FOR COMPARISON.

ADVANTAGES:

1. BASE LOAD OR CYCLIC OPERATION.
2. CLEAN FUEL.
3. SMALL UNIT SIZE AND SHORT CONSTRUCTION LEAD TIME PROVIDE FOR FLEXIBILITY OF MATCHING ANNUAL LOAD GROWTH.

DISADVANTAGES:

1. REQUIRES NEW GAS SUPPLY.

Summary
ALTERNATIVE-4
COMBINED CYCLE ON DISTILLATE

DESCRIPTION

1998: 1-235 MW COMBINED CYCLE ON DISTILLATE
 1999: 2-235 MW COMBINED CYCLES ON DISTILLATE
 2000: 1-235 MW COMBINED CYCLE ON DISTILLATE

SO2 EMISSION MODIFICATION:

1. SCRUB CRYSTAL RIVER 4&5 AT 95% AND CONVERT FROM 0.7% TO 1.1% COAL.
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL.

SO2 EMISSION TONNAGE: 2000: 107,495
 2001: 111,544

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL. (-8,000 TONS)
2. CONVERT CRYSTAL RIVER 1&2 FROM 1.1% TO 0.7% SULFUR COAL. (-18,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1&2.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	36.07%	OIL	19.29%	SOUTHERN	7.05%
NUCLEAR	11.76%	DISTILLATE	7.80%	QF	15.07%
GAS	0.52%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	22.60%	OIL	17.86%	SOUTHERN	4.08%
NUCLEAR	7.74%	DISTILLATE	32.51%	QF	9.63%
GAS	0.41%	PURCHASE	5.17%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$18,430,345,000

RISK ANALYSIS:

THERE IS A 0% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3.

ADVANTAGES:

1. SMALL UNIT SIZE AND SHORT CONSTRUCTION LEAD TIME PROVIDE FOR FLEXIBILITY OF MATCHING ANNUAL LOAD GROWTH.
2. CAN BE CONVERTED TO BURN GAS AT A LATER DATE IF PRICE AND AVAILABILITY ARE FAVORABLE.

DISADVANTAGES:

1. HIGH FUEL PRICE.
2. REQUIRES SCRUBBING CRYSTAL RIVER 4&5 TO MEET EMISSION LIMIT.

Summary **ALTERNATIVE-5** **SMALL COMBUSTION TURBINES ON GAS**

DESCRIPTION

1998: 6-40 MW COMBUSTION TURBINES ON GAS
 1999: 10-40 MW COMBUSTION TURBINES ON GAS
 2000: 8-40 MW COMBUSTION TURBINES ON GAS

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL

SO2 EMISSION TONNAGE: 2000: 126,171
 2001: 124,991

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	36.42%	OIL	15.58%	SOUTHERN	6.99%
NUCLEAR	11.76%	DISTILLATE	1.48%	QF	15.07%
GAS	10.26%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	23.01%	OIL	17.72%	SOUTHERN	4.04%
NUCLEAR	7.68%	DISTILLATE	22.76%	QF	9.55%
GAS	10.11%	PURCHASE	5.13%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$17,743,120,000

RISK ANALYSIS:

THERE IS A 27% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS THAN ALTERNATIVE-3. THIS OCCURS DURING THE LOW FUEL SCENARIOS.

ADVANTAGES:

1. GOOD HEAT RATE.
2. CLEAN FUEL
3. SMALL UNIT SIZE AND SHORT CONSTRUCTION LEAD TIME PROVIDE FOR FLEXIBILITY OF MATCHING ANNUAL LOAD GROWTH.

DISADVANTAGES:

1. REQUIRES NEW GAS SUPPLY.

Summary

ALTERNATIVE-6

OUC PURCHASE WITH COMBINED CYCLES ON GAS

DESCRIPTION

- 1997: 110 MW OUC PURCHASE (7-YEAR)
- 1998: 1-235 MW COMBINED CYCLE ON GAS
- 1999: 2-235 MW COMBINED CYCLES ON GAS
- 2000: 1-235 MW COMBINED CYCLE ON GAS

SO2 EMISSION MODIFICATION:

- 1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL.
- 2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL.

SO2 EMISSION TONNAGE: 2000: 119,221
 2001: 118,752

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

- 1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL. (-8,000 TONS)

CAPITAL INVESTMENT:

- 1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	36.39%	OIL	13.36%	SOUTHERN	6.85%
NUCLEAR	11.76%	DISTILLATE	1.48%	QF	15.07%
GAS	10.74%	PURCHASE	4.35%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	22.80%	OIL	17.56%	SOUTHERN	4.01%
NUCLEAR	7.61%	DISTILLATE	22.55%	QF	9.47%
GAS	9.82%	PURCHASE	6.18%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
 \$17,721,602,000

RISK ANALYSIS:

THERE IS A 13% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS PRIMARILY OCCURS DURING THE HIGH FUEL SCENARIOS.

ADVANTAGES:

- 1. BASE LOAD OR CYCLIC OPERATION OF COMBINED CYCLE UNITS.
- 2. CLEAN FUEL.
- 3. SMALL UNIT SIZE AND SHORT CONSTRUCTION LEAD TIME PROVIDE FOR FLEXIBILITY OF MATCHING ANNUAL LOAD GROWTH.
- 4. ATTRACTIVE PURCHASE POWER OFFER.

DISADVANTAGES:

- 1. REQUIRES NEW GAS SUPPLY.
- 2. OUC PURCHASE ONLY AVAILABLE FOR 7 YEARS. COMBINED CYCLE CAPACITY IS ADDED EARLIER THAN SYSTEM REQUIRES.

Summary **ALTERNATIVE-7** **INTEGRATED GASIFICATION COMBINED CYCLE**

DESCRIPTION

1998: 1-165 MW COMBUSTION TURBINE ON DISTILLATE
 1999: 1-580 MW IGCC ON 1.5% OR HIGHER SULFUR COAL
 2000: 1-290 MW IGCC ON 1.5% OR HIGHER SULFUR COAL

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL.
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL.

SO2 EMISSION TONNAGE: 2000: 120,211
 2001: 117,920

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:
 1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL. (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	47.74%	OIL	14.25%	SOUTHERN	5.97%
NUCLEAR	11.76%	DISTILLATE	2.37%	QF	15.07%
GAS	0.40%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	31.56%	OIL	17.59%	SOUTHERN	4.01%
NUCLEAR	7.63%	DISTILLATE	24.24%	QF	9.48%
GAS	0.40%	PURCHASE	5.09%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$18,119,506,000

RISK ANALYSIS:

THERE IS A 12% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS OCCURS DURING THE HIGH FUEL SCENARIOS.

ADVANTAGES:

1. CLEAN TECHNOLOGY. (99% FOR SO2)
2. IGCC CAN BURN INEXPENSIVE HIGH SULFUR COAL. (5% SULFUR)

DISADVANTAGES:

1. UNPROVEN TECHNOLOGY.
2. HIGH CAPITAL COST.

Summary ALTERNATIVE-8 FLUIDIZED BED

DESCRIPTION

1998: 1-165 MW COMBUSTION TURBINE ON DISTILLATE
1999: 3-150 MW FLUIDIZED BED
2000: 2-150 MW FLUIDIZED BED

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL

SO2 EMISSION TONNAGE:

2000: 125,070
2001: 122,828

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	46.74%	OIL	14.87%	SOUTHERN	6.08%
NUCLEAR	11.76%	DISTILLATE	2.62%	QF	15.07%
GAS	0.42%	PURCHASE	2.44%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	30.72%	OIL	17.80%	SOUTHERN	4.06%
NUCLEAR	7.72%	DISTILLATE	24.54%	QF	9.60%
GAS	0.41%	PURCHASE	5.15%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$18,465,748,000

RISK ANALYSIS:

THERE IS A 0% CHANCE THAT THIS ALTERNATIVE HAS A LOWER
CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3.

ADVANTAGES:

1. FLUIDIZED BED UNITS CAN BURN INEXPENSIVE HIGH SULFUR FUEL (5% SULFUR)
2. SMALL UNIT CAN BETTER MATCH ANNUAL LOAD GROWTH.

DISADVANTAGES:

1. UNPROVEN TECHNOLOGY.
2. HIGH CAPITAL COST.

Summary

ALTERNATIVE-9

IGCC - ORIMULSION

DESCRIPTION

1998: 1-593 MW IGCC ON ORIMULSION (537 MW NET)
2000: 2-165 MW COMBUSTION TURBINES ON DISTILLATE

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL.
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL.

SO2 EMISSION TONNAGE: 2000: 122,590
 2001: 126,867

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL. (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	35.02%	OIL	15.87%	SOUTHERN	6.28%
NUCLEAR	11.76%	DISTILLATE	3.44%	QF	15.07%
GAS	0.44%	PURCHASE	2.44%	ORIMULSION	9.68%

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	23.09%	OIL	17.79%	SOUTHERN	4.06%
NUCLEAR	7.71%	DISTILLATE	26.19%	QF	9.59%
GAS	0.41%	PURCHASE	5.14%	ORIMULSION	6.02%

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$17,845,542,000

RISK ANALYSIS:

THERE IS A 5% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS OCCURS DURING HIGH FUEL/BASE FUEL, LOW DEMAND AND ENERGY SCENARIOS.

ADVANTAGES:

1. LOW FUEL COST.
2. CLEAN TECHNOLOGY.
3. POSSIBILITY OF EQUITY PARTNERSHIP WITH TEXACO.

DISADVANTAGES:

1. FUEL SUPPLY RISK. (LIMITED FOREIGN SUPPLIER)
2. UNPROVEN TECHNOLOGY.

Summary ALTERNATIVE-10 CAJUN UPS PURCHASE

DESCRIPTION

1998: 376 MW CAJUN UPS PURCHASE
1999: 1-235 MW COMBINED CYCLE ON GAS
2000: 2-165 MW COMBUSTION TURBINES ON GAS

SO2 EMISSION MODIFICATION:

1. CONVERT CRYSTAL RIVER 1-2 FROM 1.1% TO 0.7% SULFUR COAL
2. CONVERT BARTOW FROM 2.5% TO 1.0% SULFUR OIL

SO2 EMISSION TONNAGE:

2000: 123,077
2001: 125,517

AVAILABLE FUTURE EMISSION CONTROL MEASURES:

OPERATIONAL:

1. CONVERT TURNER & SUWANNEE FROM 2.5% TO 1.0% SULFUR OIL (-8,000 TONS)

CAPITAL INVESTMENT:

1. SCRUB CRYSTAL RIVER 1,2,4,5.

GENERATION MIX BY FUEL TYPES IN 2001:

COAL	36.36%	OIL	15.60%	SOUTHERN	6.48%
NUCLEAR	11.76%	DISTILLATE	1.80%	QF	15.07%
GAS	4.62%	PURCHASE	8.31%		

CAPACITY MIX BY FUEL TYPES IN 2001:

COAL	23.05%	OIL	17.76%	SOUTHERN	4.05%
NUCLEAR	7.70%	DISTILLATE	22.80%	QF	9.57%
GAS	6.13%	PURCHASE	8.94%		

ACCUMULATED PRESENT WORTH REVENUE REQUIREMENT (1991-2020):
\$17,742,292,000

RISK ANALYSIS:

THERE IS A 34% CHANCE THAT THIS ALTERNATIVE HAS A LOWER CUMULATIVE PRESENT WORTH REVENUE REQUIREMENT THAN ALTERNATIVE-3. THIS PRIMARILY OCCURS DURING THE HIGH FUEL SCENARIOS.

ADVANTAGES:

1. BASE LOAD OR CYCLIC OPERATION OF COMBINED CYCLE UNITS.
2. CLEAN FUEL
3. NO CAPITAL INVESTMENT FOR CAJUN PURCHASE.

DISADVANTAGES:

1. UTILIZES TIE LINE CAPACITY.
2. REQUIRES NEW GAS SUPPLY.

RESERVE MARGIN FOR ALTERNATIVE 1 = PC UNIT (LARGE) & CT's (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6164	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.8%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.8%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	330 (8)	7719	400	919	9038	7847	1391	18.2%
SUMMER 99	6855	0	270 (8)	7125	400	919	8444	7019	1425	20.3%
WINTER 99/00	7719	249 (11)	700 (9)	8170	400	919	9489	7762	1727	22.2%
SUMMER 00	7125	229 (11)	679 (9)	7575	400	919	8694	7188	1706	23.7%
WINTER 00/01	8170	60 (11)	0 (10)	8110	400	919	9429	7950	1479	18.6%
SUMMER 01	7575	50 (11)	0 (10)	7525	400	919	8644	7365	1479	20.1%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Rio Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)

(5) Combustion turbine addition @ Deary (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4

(12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 2 = PC UNIT (SMALL) & CT's (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6164	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5909	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	0	7389	400	919	9036	7847	1391	18.2%
SUMMER 99	6855	0	0	6855	400	919	8444	7019	1425	20.3%
WINTER 99/00	7719	0	0	7719	400	919	9239	7762	1477	19.0%
SUMMER 00	7125	0	0	7125	400	919	8651	7188	1463	20.3%
WINTER 00/01	7920	0	0	7920	400	919	9344	7950	1394	17.5%
SUMMER 01	7332	0	0	7332	400	919	8736	7365	1371	18.6%

- (1) Firm peak demand is forecasted demand less interruptible load.
 (2) Port St. Joe P1 and Plo Pinar P1 reactivation
 (3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 780 MW (16 MW increase)
 (4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)
 (5) Combustion turbine addition @ Deary (4 units)
 (6) Combustion turbine addition @ Intercession City (4 units)

- (7) University Project
 (8) Future FPC unit addition(s)
 (9) Future FPC unit addition(s)
 (10) Future FPC unit addition(s)
 (11) Higgins Steam Units 1-3 & Higgins P1-P4
 (12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 3 = CC UNITS (GAS)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	8571	0	0	8571	400	112	7083	5834	1249	21.4%
SUMMER 91	8184	0	28 (2)	8192	400	135	8727	5559	1168	21.0%
WINTER 91/92	8571	0	50 (2&3)	8621	400	168	7189	6081	508	7.8%
SUMMER 92	8192	0	15 (4)	8207	400	168	8775	5809	966	16.8%
WINTER 92/93	8621	0	364 (5)	8985	400	203	7588	6921	667	9.8%
SUMMER 93	8207	0	304 (5)	8511	400	356	7267	6046	1221	20.2%
WINTER 93/94	8985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	8511	0	344 (6&7)	8855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	0	7389	400	919	8943	7647	1296	16.9%
SUMMER 99	6855	0	0	6855	400	919	8374	7019	1355	19.3%
WINTER 99/00	7624	0	235 (8)	7824	400	919	9164	7762	1402	18.1%
SUMMER 00	7055	0	200 (8)	7055	400	919	8545	7188	1357	18.9%
WINTER 00/01	7845	249 (11)	470 (9)	7845	400	919	9339	7950	1389	17.5%
SUMMER 01	7226	229 (11)	400 (9)	7226	400	919	8695	7365	1330	18.1%
		60 (12)	235 (10)	8020	400					
		50 (12)	200 (10)	7376	400					

(1) Firm peak demand is forecasted demand less interruptible load.
 (2) Port St. Joe P1 and Rio Pinar P1 reactivation
 (3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)
 (4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)
 (5) Combustion turbine addition @ Debarry (4 units)
 (6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project
 (8) Future FPC unit addition(s)
 (9) Future FPC unit addition(s)
 (10) Future FPC unit addition(s)
 (11) Higgins Steam Units 1-3 & Higgins P1-P4
 (12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 4 = CC UNITS (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6184	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8458	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	235 (8)	7624	400	919	8943	7647	1296	16.9%
SUMMER 99	6855	0	200 (8)	7055	400	919	8374	7019	1355	19.3%
WINTER 99/00	7624	307 (11)	470 (9)	7787	400	919	9106	7762	1344	17.3%
SUMMER 00	7055	285 (11)	400 (9)	7170	400	919	8489	7188	1301	18.1%
WINTER 00/01	7787	60 (12)	235 (10)	7962	400	919	9281	7950	1331	16.7%
SUMMER 01	7170	50 (12)	200 (10)	7320	400	919	8639	7365	1274	17.3%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Rio Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)

(5) Combustion turbine addition @ Debarry (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4
& Scrubber Retrofit of Crystal River 4-5

(12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 5 = SMALL CT UNITS (GAS)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6164	0	26 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6048	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	16.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.6%
WINTER 95/96	7389	0	0	7389	400	769	8553	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7538	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	0	7389	400	919	8948	7647	1301	17.0%
SUMMER 99	6855	0	0	6855	400	919	8396	7019	1377	19.8%
WINTER 99/00	7629	249 (11)	400 (9)	7629	400	919	9099	7762	1337	17.2%
SUMMER 00	7077	229 (11)	370 (9)	7218	400	919	8537	7188	1349	18.8%
WINTER 00/01	7780	60 (12)	320 (10)	8040	400	919	9359	7950	1409	17.7%
SUMMER 01	7218	50 (12)	296 (10)	7464	400	919	8783	7365	1418	19.2%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Palo Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 780 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 736 MW (15 MW increase)

(5) Combustion turbine addition @ Debarry (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4

(12) Avon Park P1-P2

RESERVE MARGIN FOR
ALTERNATIVE 8 = OUC PURCHASE & CC's (GAS)

ALTERNATIVE 8 = OUC PURCHASE										
SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	FIRM RESERVES (%)
				6571	400	112	7063	5834	1249	21.4%
				6192	400	135	6727	5559	1168	21.0%
WINTER 90/91	6571	0	0	6571	400	112	7063	5834	1249	21.4%
SUMMER 91	6164	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1253	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1443	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8818	7536	1282	17.0%
SUMMER 98	6855	0	0	6855	400	919	8284	6873	1411	20.5%
WINTER 98/99	7389	0	110 OUC	7499	400	919	9053	7647	1406	18.4%
SUMMER 99	6855	0	110 OUC	6965	400	919	8484	7019	1465	20.9%
WINTER 99/00	7499	0	235 (8)	7734	400	919	9274	7762	1512	19.5%
SUMMER 00	6965	0	200 (8)	7165	400	919	8655	7188	1467	20.4%
WINTER 00/01	7734	249 (11)	470 (9)	7955	400	919	9449	7950	1499	18.9%
SUMMER 01	7165	229 (11)	400 (9)	7336	400	919	8805	7365	1440	19.5%
WINTER 01/02	7955	60 (12)	235 (10)	8130	400	919	9449	7950	1499	18.9%
SUMMER 02	7336	50 (12)	200 (10)	7486	400	919	8805	7365	1440	19.5%

(7) University Project
(8) Future FPC unit addition(s)
(9) Future FPC unit addition(s)
FPC unit addition(s)

(1) Firm peak demand is forecasted demand less interruptible load.

- (1) Firm peak demand is forecasted demand less interruption
- (2) Port St. Joe P1 and Fio Pinar P1 reactivation
- (3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)
- (4) Long term rating for Crystal River 3 beginning SUMMER 92 = 736 MW (15 MW increase)
- (5) Combustion turbine addition @ Debarry (4 units)
- (6) Combustion turbine addition @ Intercession City (4 units)

- (7) University Project
- (8) Future FPC unit addition(s)
- (9) Future FPC unit addition(s)
- (10) Future FPC unit addition(s)
- (11) Higgins Steam Units 1-3 & Higgins P1-P4
- (12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 7 = IGCC UNITS (LARGE, SMALL) & CT (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
										21.4%
				8571	400	112	7083	5834	1249	21.0%
				8192	400	135	8727	5559	1168	
WINTER 90/91	8571	0	0							7.6%
SUMMER 91	8184	0	28 (2)	8192	400				508	16.8%
				8821	400	168	7189	6881	966	
WINTER 91/92	8571	0	50 (2&3)	8207	400	168	6775	5809		9.6%
SUMMER 92	8192	0	15 (4)				7588	6921	667	20.2%
				8985	400	203	7267	6046	1221	
WINTER 92/93	8821	0	364 (5)	8511	400	358				18.9%
SUMMER 93	8207	0	304 (5)				8379	7047	1332	26.1%
				7389	400	590	7845	6223	1622	
WINTER 93/94	8985	0	404 (6&7)	6855	400	590				17.3%
SUMMER 94	8511	0	344 (6&7)				8413	7172	1241	22.8%
				7389	400	624	7879	6418	1461	
WINTER 94/95	7389	0	0	6855	400	624				17.2%
SUMMER 95	6855	0	0				8558	7300	1258	22.0%
				7389	400	769	8024	6575	1449	
WINTER 95/96	7389	0	0	6855	400	769				15.3%
SUMMER 96	6855	0	0				8558	7422	1136	19.3%
				7389	400	769	8024	6727	1297	
WINTER 96/97	7389	0	0	6855	400	769				15.5%
SUMMER 97	6855	0	0				8708	7536	1172	18.9%
				7389	400	919	8174	6873	1301	
WINTER 97/98	7389	0	0	6855	400	919				16.0%
SUMMER 98	6855	0	0				8873	7647	1226	18.4%
				7554	400	919	8309	7019	1290	
WINTER 98/99	7389	0	165 (8)	6990	400	919				18.6%
SUMMER 99	6855	0	135 (8)				9204	7762	1442	19.4%
				7885	400	919	8580	7188	1392	
WINTER 99/00	7554	249 (11)	580 (9)	7261	400	919				18.7%
SUMMER 00	6990	229 (11)	500 (9)				9434	7950	1484	19.2%
				8115	400	919	8780	7365	1415	
WINTER 00/01	7885	60 (12)	290 (10)	7461	400					
SUMMER 01	7261	50 (12)	250 (10)							

(1) Firm peak demand is forecasted demand less interruptible load.

- (2) Port St. Joe P1 and Rio Pinar P1 reactivation
 (3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)
 (4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)
 (5) Combustion turbine addition @ Debarry (4 units)
 (6) Combustion turbine addition @ Intercession City (4 units)

- (7) University Project
 (8) Future FPC unit addition(s)
 (9) Future FPC unit addition(s)
 (10) Future FPC unit addition(s)
 (11) Higgins Steam Units 1-3 & Higgins P1-P4
 (12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 8 = FLUIDIZED BED & CT (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6184	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	3	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	165 (8)	7554	400	919	8873	7647	1226	16.0%
SUMMER 99	6855	0	135 (8)	6990	400	919	8309	7019	1290	18.4%
WINTER 99/00	7554	249 (11)	450 (9)	7755	400	919	9074	7762	1312	16.9%
SUMMER 00	6990	229 (11)	438 (9)	7199	400	919	8518	7186	1330	18.5%
WINTER 00/01	7755	60 (12)	300 (10)	7995	400	919	9314	7950	1364	17.2%
SUMMER 01	7199	50 (12)	292 (10)	7441	400	919	8760	7365	1395	18.9%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Rio Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)

(5) Combustion turbine addition @ Debarry (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4

(12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 9 = IGCC (ORIMULSION) & CT's (DIST)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6164	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6416	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	16.9%
WINTER 98/99	7389	0	593 (8)	7982	400	919	9301	7847	1454	21.6%
SUMMER 99	6855	0	570 (8)	7425	400	919	8744	7019	1725	24.6%
WINTER 99/00	7982	249 (11)	0 (9)	7733	400	919	9052	7762	1290	16.6%
SUMMER 00	7425	229 (11)	0 (9)	7196	400	919	8515	7188	1327	18.5%
WINTER 00/01	7733	60 (12)	330 (10)	8003	400	919	9322	7950	1372	17.3%
SUMMER 01	7196	50 (12)	270 (10)	7416	400	919	8735	7365	1370	18.6%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Rio Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 736 MW (15 MW increase)

(5) Combustion turbine addition @ Debarry (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4

(12) Avon Park P1-P2

RESERVE MARGIN FOR ALTERNATIVE 10 = UPS PURCHASE & CC's,CT (GAS)

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
				8571	400	112	7083	5834	1249	21.4%
				8192	400	135	8727	5559	1168	21.0%
WINTER 90/91	8571	0	0							
SUMMER 91	8184	0	28 (2)	8192	400	135		6681	508	7.8%
								5809	968	16.6%
WINTER 91/92	8571	0	50 (2&3)	8621	400	168	7189			
SUMMER 92	8192	0	15 (4)	8207	400	168	6775	6921	667	9.6%
								6046	1221	20.2%
WINTER 92/93	8621	0	364 (5)	8985	400	203	7588			
SUMMER 93	8207	0	304 (5)	8511	400	356	7267	7047	1332	18.9%
								6223	1622	26.1%
WINTER 93/94	8985	0	404 (6&7)	7389	400	590	8379			
SUMMER 94	8511	0	344 (6&7)	6855	400	590	7845	7172	1241	22.8%
								6418	1461	
WINTER 94/95	7389	0	0	7389	400	624	8558	7300	1258	17.2%
SUMMER 95	6855	0	0	6855	400	624	8024	6575	1449	22.0%
WINTER 95/96	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 96	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 96/97	7389	0	0	7389	400	769	8558	7536	1172	15.5%
SUMMER 97	6855	0	0	6855	400	769	8024	6873	1301	18.9%
WINTER 97/98	7389	0	0	7389	400	919	8708	7647	1437	18.8%
SUMMER 98	6855	0	0	6855	400	919	8174	7019	1531	21.8%
WINTER 98/99	7389	0	376 UPS	7765	400	919	9084	7762	1308	16.8%
SUMMER 99	6855	0	376 UPS	7231	400	919	8550	7188	1333	18.5%
WINTER 99/00	7765	249 (11)	235 (9)	7751	400	919	9340	7950	1390	17.5%
SUMMER 00	7231	229 (11)	200 (9)	7202	400	919	8741	7365	1376	18.7%
WINTER 00/01	7751	60 (12)	330 (10)	8021	400					
SUMMER 01	7202	50 (12)	270 (10)	7422	400					

(1) Firm peak demand is forecasted demand less interruptible load.

- (2) Port St. Joe P1 and Rio Pinar P1 reactivation
- (3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)
- (4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)
- (5) Combustion turbine addition @ Debarry (4 units)
- (6) Combustion turbine addition @ Intercession City (4 units)

- (7) University Project
- (8) Future FPC unit addition(s)
- (9) Future FPC unit addition(s)
- (10) Future FPC unit addition(s)
- (11) Higgins Steam Units 1-3 & Higgins P1-P4
- (12) Avon Park P1-P2

RESERVE MARGIN FOR FUTURE CONTRACTED COGEN @ 75% PROBABILITY

SEASON	EXISTING FPC CAPACITY (MW)	RETIRED FPC CAPACITY (MW)	NEW FPC CAPACITY (MW)	TOTAL INSTALLED CAPACITY (MW)	FIRM PURCHASE CAPACITY (MW)	FIRM COGEN PURCHASE CAPACITY (MW)	TOTAL AVAILABLE CAPACITY (MW)	(1) FIRM PEAK DEMAND (MW)	FIRM RESERVES (MW)	(%)
WINTER 90/91	6571	0	0	6571	400	112	7083	5834	1249	21.4%
SUMMER 91	6164	0	28 (2)	6192	400	135	6727	5559	1168	21.0%
WINTER 91/92	6571	0	50 (2&3)	6621	400	168	7189	6681	508	7.6%
SUMMER 92	6192	0	15 (4)	6207	400	168	6775	5809	966	16.6%
WINTER 92/93	6621	0	364 (5)	6985	400	203	7588	6921	667	9.6%
SUMMER 93	6207	0	304 (5)	6511	400	356	7267	6046	1221	20.2%
WINTER 93/94	6985	0	404 (6&7)	7389	400	590	8379	7047	1332	18.9%
SUMMER 94	6511	0	344 (6&7)	6855	400	590	7845	6223	1622	26.1%
WINTER 94/95	7389	0	0	7389	400	624	8413	7172	1241	17.3%
SUMMER 95	6855	0	0	6855	400	624	7879	6418	1461	22.8%
WINTER 95/96	7389	0	0	7389	400	769	8558	7300	1258	17.2%
SUMMER 96	6855	0	0	6855	400	769	8024	6575	1449	22.0%
WINTER 96/97	7389	0	0	7389	400	769	8558	7422	1136	15.3%
SUMMER 97	6855	0	0	6855	400	769	8024	6727	1297	19.3%
WINTER 97/98	7389	0	0	7389	400	919	8708	7536	1172	15.5%
SUMMER 98	6855	0	0	6855	400	919	8174	6873	1301	18.9%
WINTER 98/99	7389	0	0	7389	400	919	8708	7647	1061	13.9%
SUMMER 99	6855	0	0	6855	400	919	8174	7019	1155	16.4%
WINTER 99/00	7389	249 (11)	0 (9)	7140	400	919	8459	7762	697	9.0%
SUMMER 00	6855	229 (11)	0 (9)	6626	400	919	7945	7188	757	10.5%
WINTER 00/01	7140	60 (12)	0 (10)	7080	400	919	8399	7950	449	5.6%
SUMMER 01	6626	50 (12)	0 (10)	6576	400	919	7895	7365	530	7.2%

(1) Firm peak demand is forecasted demand less interruptible load.

(2) Port St. Joe P1 and Fio Pinar P1 reactivation

(3) Long term rating for Crystal River 3 beginning WINTER 91/92 = 760 MW (16 MW increase)

(4) Long term rating for Crystal River 3 beginning SUMMER 92 = 738 MW (15 MW increase)

(5) Combustion turbine addition @ Debar (4 units)

(6) Combustion turbine addition @ Intercession City (4 units)

(7) University Project

(8) Future FPC unit addition(s)

(9) Future FPC unit addition(s)

(10) Future FPC unit addition(s)

(11) Higgins Steam Units 1-3 & Higgins P1-P4

(12) Avon Park P1-P2

Table LOLP-1
Loss of Load Probability For 10 Alternative Resource Plans

	Alt. 1	Alt. 2	Alt. 3	Alt. 4	Alt. 5	Alt. 6	Alt. 7	Alt. 8	Alt. 9	Alt. 10
1991	0.36825	0.36825	0.36825	0.36825	0.36825	0.36825	0.36825	0.36825	0.36825	0.36825
1992	1.04135	1.04135	1.04135	1.04135	1.04135	1.04135	1.04135	1.04135	1.04135	1.04135
1993	0.36477	0.36477	0.36477	0.36477	0.36477	0.36477	0.36477	0.36477	0.36477	0.36477
1994	0.03907	0.03907	0.03907	0.03907	0.03907	0.03907	0.03907	0.03907	0.03907	0.03907
1995	0.08281	0.08281	0.08281	0.08281	0.08281	0.08281	0.08281	0.08281	0.08281	0.08281
1996	0.11863	0.11863	0.11863	0.11863	0.11863	0.11863	0.11863	0.11863	0.11863	0.11863
1997	0.01212	0.01212	0.01212	0.01212	0.01212	0.01195	0.01212	0.01212	0.01212	0.01212
1998	0.01171	0.01171	0.01177	0.01178	0.01184	0.00695	0.01183	0.01183	0.01160	0.01158
1999	0.00647	0.00658	0.00985	0.01003	0.00869	0.00573	0.01342	0.01325	0.00344	0.00659
2000	0.00275	0.00488	0.00634	0.00781	0.00591	0.00373	0.00973	0.00832	0.01395	0.01112
2001	0.01418	0.01415	0.01363	0.01670	0.00732	0.00811	0.01893	0.01381	0.02102	0.01588

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Appendix F:
COMPUTER MODELS AND
PROGRAMS DESCRIPTIONS

COMPUTER MODELS

TIGER

This model provides a probabilistic assessment of capacity need by evaluating the loss of load probability each day of the year. This can be done on a net (assisted) or isolated (unassisted) basis. The calculation of the loss of firm load is made after adjusting the system for maintenance, taking into consideration daily peak demand, net transactions, and interruptible loads.

PROMOD III

PROMOD III is a detailed production costing model licensed to Florida Power Corporation by Energy Management Associates. Its primary function is to produce unit operation and fuel consumption data. This information is used to calculate SO₂ emissions for the supply side alternatives.

PROSCREEN II

PROSCREEN II is also licensed to Florida Power Corporation by Energy Management Associates. PROSCREEN II is a production costing model linked to a capital expenditure and recovery module. It is used to assess the relative economics of future generation expansion scenarios. Cumulative present worth of revenue requirements are calculated with this model.

COMPUTER PROGRAMS

LOAD AND CAPACITY

The LOAD AND CAPACITY program is a lotus spreadsheet developed by FPC. Its purpose is to calculate firm capacity reserves. These calculations consider existing and retired capacity, future FPC capacity additions, firm purchase power, cogeneration, and firm peak demand.

STATISTICAL ANALYSIS SYSTEM

SAS is a computer software system licensed to Florida Power Corporation by the SAS Institute, Inc. SAS is used extensively for the analysis of PROMOD and PROSCREEN output. Its primary applications are in the calculation of SO₂ emissions and the comparison of cumulative present worth revenue requirements.

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Appendix G:

APH FORMS

FLORIDA POWER CORPORATION
HISTORY AND FORECAST
BASE (MOST PROBABLE) LOAD FORECAST

INDIVIDUAL UTILITY FORM 1.1
PAGE 1 OF 3

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		SUMMER PEAK DEMAND - (MW)											ENERGY - (GWH)	
		INTER- RUPTIBLE LOAD (MW)	LOAD MANAGE- MENT (MW)	OF LOAD (MW)	NET DEMAND (MW)			INTER- RUPTIBLE LOAD (MW)	LOAD MANAGE- MENT (MW)	OF LOAD (MW)	NET DEMAND (MW)		NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
YEAR	TOTAL (MW)					YEAR	TOTAL (MW)					YEAR		
1981	4366	208	0	11	4147	1980 /81	5349	290	0	11	5048	1981	20924	47.3%
1982	4101	173	1	14	3913	1981 /82	5359	139	0	12	5208	1982	20098	44.1%
1983	4691	163	40	41	4447	1982 /83	4764	149	27	36	4552	1983	21732	54.5%
1984	4277	201	72	42	3962	1983 /84	5098	168	93	42	4795	1984	20708	49.3%
1985	4718	230	97	43	4348	1984 /85	6206	285	135	42	5744	1985	22377	44.5%
1986	4708	177	116	58	4357	1985 /86	6211	187	181	51	5792	1986	22685	44.7%
1987	5255	267	250	58	4680	1986 /87	5345	206	200	58	4881	1987	24292	56.8%
1988	5378	222	258	61	4837	1987 /88	6200	229	328	61	5582	1988	25848	52.9%
1989	5805	276	207	66	5256	1988 /89	6696	237	493	66	5900	1989	27847	53.9%
1990	5882	230	212	66	5374	1989 /90	7631	301	650	66	6614	1990	27805	48.0%
81-90 AAGR	3.37%				2.92%	81-90 AAGR	4.03%				3.05%	81-90 AAGR	3.21%	
1991	6229	262	342	66	5559	1990 /91	6122	196	490	66	5370	1991	28652	60.9%
1992	6539	267	397	66	5809	1991 /92	7718	267	704	66	6681	1992	30472	52.1%
1993	6840	272	456	66	6046	1992 /93	8079	272	820	66	6921	1993	32037	52.8%
1994	7081	277	515	66	6223	1993 /94	8327	277	937	66	7047	1994	33592	54.4%
1995	7374	316	574	66	6418	1994 /95	8608	316	1054	66	7172	1995	35244	56.1%
1996	7596	321	634	66	6575	1995 /96	8857	321	1170	66	7300	1996	36597	57.2%
1997	7812	326	693	66	6727	1996 /97	9101	326	1287	66	7422	1997	37893	58.3%
1998	8021	330	752	66	6873	1997 /98	9335	330	1403	66	7536	1998	39149	59.3%
1999	8231	335	811	66	7019	1998 /99	9568	335	1520	66	7647	1999	40386	60.3%
2000	8438	343	841	66	7188	1999 / 0	9800	343	1629	66	7762	2000	41611	61.2%
91-00 AAGR	3.43%				2.90%	91-00 AAGR	5.37%				4.18%	91-00 AAGR	4.23%	
2001	8638	351	856	66	7365	2000 / 1	10026	351	1659	66	7950	2001	42814	61.5%
2002	8838	359	871	66	7542	2001 / 2	10252	359	1689	66	8138	2002	44028	61.8%
2003	9040	366	887	66	7721	2002 / 3	10481	366	1718	66	8331	2003	45243	62.0%
2004	9237	374	902	66	7895	2003 / 4	10711	374	1748	66	8523	2004	46461	62.2%
2005	9438	384	917	66	8071	2004 / 5	10945	384	1779	66	8716	2005	47651	62.4%
2006	9640	394	932	66	8248	2005 / 6	11184	394	1808	66	8916	2006	48852	62.5%
2007	9840	403	947	66	8424	2006 / 7	11426	403	1838	66	9119	2007	50055	62.7%
2008	10042	413	962	66	8601	2007 / 8	11675	413	1868	66	9328	2008	51271	62.7%
2009	10244	423	977	66	8778	2008 / 9	11923	423	1898	66	9536	2009	52462	62.8%
2010	10446	432	993	66	8955	2009 /10	12175	432	1928	66	9749	2010	53651	62.8%
01-10 AAGR	2.13%				2.20%	01-10 AAGR	2.18%				2.29%	01-10 AAGR	2.54%	
91-10 AAGR	2.76%				2.54%	91-10 AAGR	3.68%				3.19%	91-10 AAGR	3.36%	

NOTE: COLUMN (2) = SUM OF COLUMNS (3) THROUGH (6). COLUMN (8) = SUM OF COLUMNS (9) THROUGH (12).
COLUMN (5) & (11), SELF-SERVICE GENERATION, ARE OF LOAD SERVED BY OF GENERATION.
COLUMN (6) & (12) = RECORDED DEMAND MINUS INTERRUPTIBLE SERVED MINUS L.M. SERVED.
1990 /91 WINTER PEAK DEMAND DATA IS ACTUAL.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST
LOW LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		SUMMER PEAK DEMAND - (MW)											ENERGY - (GWH)	
		INTER-	LOAD	QF	NET			INTER-	LOAD	QF	NET		NET ENERGY	LOAD
		RUPTIBLE	MANAGE-	LOAD	DEMAND			RUPTIBLE	MANAGE-	LOAD	DEMAND		FOR LOAD	FACTOR
YEAR	TOTAL	LOAD	MENT	(MW)	(MW)	YEAR	TOTAL	LOAD	MENT	(MW)	(MW)	YEAR	(GWH)	(%)
1981	4366	208	0	11	4147	1980 /81	5349	290	0	11	5048	1981	20924	47.3%
1982	4101	173	1	14	3913	1981 /82	5359	139	0	12	5208	1982	20098	44.1%
1983	4691	163	40	41	4447	1982 /83	4764	149	27	36	4552	1983	21732	54.5%
1984	4277	201	72	42	3962	1983 /84	5098	168	93	42	4795	1984	20708	49.3%
1985	4718	230	97	43	4348	1984 /85	6206	285	135	42	5744	1985	22377	44.5%
1986	4708	177	116	58	4357	1985 /86	6211	187	181	51	5792	1986	22685	44.7%
1987	5255	267	250	58	4680	1986 /87	5345	206	200	58	4881	1987	24292	56.8%
1988	5378	222	258	61	4837	1987 /88	6200	229	328	61	5582	1988	25848	52.9%
1989	5805	276	207	66	5256	1988 /89	6696	237	493	66	5900	1989	27847	53.9%
1990	5882	230	212	66	5374	1989 /90	7631	301	650	66	6614	1990	27805	48.0%
81-90 AAGR	3.37%				2.92%	81-90 AAGR	4.03%				3.05%	81-90 AAGR	3.21%	
1991	6229	262	342	66	5559	1990 /91	6122	196	490	66	5370	1991	27871	59.3%
1992	6337	267	397	66	5607	1991 /92	7487	267	704	66	6450	1992	29453	52.1%
1993	6574	272	456	66	5780	1992 /93	7776	272	820	66	6618	1993	30685	52.9%
1994	6758	277	515	66	5900	1993 /94	7963	277	937	66	6683	1994	31919	54.5%
1995	6986	316	574	66	6030	1994 /95	8177	316	1054	66	6741	1995	33219	56.3%
1996	7152	321	634	66	6131	1995 /96	8366	321	1170	66	6809	1996	34238	57.4%
1997	7310	326	693	66	6225	1996 /97	8550	326	1287	66	6871	1997	35195	58.5%
1998	7441	330	752	66	6293	1997 /98	8702	330	1403	66	6903	1998	36061	59.5%
1999	7584	335	811	66	6372	1998 /99	8866	335	1520	66	6945	1999	36838	60.6%
2000	7723	343	841	66	6473	1999 / 0	9031	343	1629	66	6993	2000	37669	61.5%
91-00 AAGR	2.42%				1.71%	91-00 AAGR	4.41%				2.98%	91-00 AAGR	3.40%	
2001	7855	351	856	66	6582	2000 / 1	9184	351	1659	66	7108	2001	38476	61.8%
2002	7980	359	871	66	6684	2001 / 2	9329	359	1689	66	7215	2002	39252	62.1%
2003	8110	366	887	66	6791	2002 / 3	9481	366	1718	66	7331	2003	40049	62.4%
2004	8230	374	902	66	6888	2003 / 4	9628	374	1748	66	7440	2004	40815	62.6%
2005	8359	384	917	66	6992	2004 / 5	9784	384	1779	66	7555	2005	41578	62.8%
2006	8470	394	932	66	7078	2005 / 6	9924	394	1808	66	7656	2006	42252	63.0%
2007	8595	403	947	66	7179	2006 / 7	10083	403	1838	66	7776	2007	43008	63.1%
2008	8706	413	962	66	7265	2007 / 8	10231	413	1868	66	7884	2008	43687	63.3%
2009	8833	423	977	66	7367	2008 / 9	10396	423	1898	66	8009	2009	44432	63.3%
2010	8944	432	993	66	7453	2009 /10	10546	432	1928	66	8120	2010	45079	63.4%
01-10 AAGR	1.45%				1.39%	01-10 AAGR	1.55%				1.49%	01-10 AAGR	1.78%	
91-10 AAGR	1.92%				1.56%	91-10 AAGR	2.90%				2.20%	91-10 AAGR	2.56%	

NOTE: COLUMN (2) = SUM OF COLUMNS (3) THROUGH (6). COLUMN (8) = SUM OF COLUMNS (9) THROUGH (12).
COLUMN (5) & (11), SELF-SERVICE GENERATION, ARE QF LOAD SERVED BY QF GENERATION.
COLUMN (6) & (12) = RECORDED DEMAND MINUS INTERRUPTIBLE SERVED MINUS L.M. SERVED.
1990 /91 WINTER PEAK DEMAND DATA IS ACTUAL.

FLORIDA POWER CORPORATION

HISTORY AND FORECAST
HIGH LOAD FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
YEAR	TOTAL (MW)	INTER- RUPTIBLE LOAD (MW)	LOAD MANAGE- MENT (MW)	QF LOAD (MW)	NET DEMAND (MW)	YEAR	TOTAL (MW)	INTER- RUPTIBLE LOAD (MW)	LOAD MANAGE- MENT (MW)	QF LOAD (MW)	NET DEMAND (MW)	YEAR	NET ENERGY FOR LOAD (GWH)	LOAD FACTOR (%)
1981	4366	208	0	11	4147	1980 / 81	5349	290	0	11	5048	1981	20924	47.3%
1982	4101	173	1	14	3913	1981 / 82	5359	139	0	12	5208	1982	20098	44.1%
1983	4691	163	40	41	4447	1982 / 83	4764	149	27	36	4552	1983	21732	54.5%
1984	4277	201	72	42	3962	1983 / 84	5098	168	93	42	4795	1984	20708	49.3%
1985	4718	230	97	43	4348	1984 / 85	6206	285	135	51	5744	1985	22377	44.5%
1986	4708	177	116	58	4357	1985 / 86	6211	187	181	58	5792	1986	22685	44.7%
1987	5255	267	250	58	4680	1986 / 87	5345	206	200	61	4881	1987	24292	56.8%
1988	5378	222	207	61	4837	1987 / 88	6200	229	328	66	5582	1988	25848	52.9%
1989	5805	276	212	66	5256	1988 / 89	6696	237	493	66	5900	1989	27847	53.9%
1990	5882	230			5374	1989 / 90	7631	301	650	66	6614	1990	27805	48.0%
81-90 AAGR	3.37%					2.92% 81-90 AAGR	4.03%				3.05%	81-90 AAGR	3.21%	
1991	6229	262	342	66	5559	1990 / 91	6122	196	490	66	5370	1991	28993	61.6%
1992	6630	267	397	66	5900	1991 / 92	7822	267	704	66	6785	1992	30933	52.0%
1993	6966	272	456	66	6172	1992 / 93	8223	272	820	66	7065	1993	32685	52.8%
1994	7246	277	515	66	6388	1993 / 94	8513	277	937	66	7233	1994	34455	54.4%
1995	7595	316	574	66	6639	1994 / 95	8854	316	1054	66	7418	1995	36412	56.0%
1996	7864	321	634	66	6843	1995 / 96	9153	321	1170	66	7596	1996	38025	57.1%
1997	8137	326	693	66	7052	1996 / 97	9458	326	1287	66	7779	1997	39646	58.2%
1998	8410	330	752	66	7262	1997 / 98	9760	330	1403	66	7961	1998	41264	59.2%
1999	8675	335	811	66	7463	1998 / 99	10050	335	1520	66	8129	1999	42825	60.1%
2000	8948	343	841	66	7698	1999 / 0	10349	343	1629	66	8311	2000	44426	61.0%
91-00 AAGR	4.11%					3.68% 91-00 AAGR	6.01%				4.97%	91-00 AAGR	4.86%	
2001	9203	351	856	66	7930	2000 / 1	10634	351	1659	66	8558	2001	45950	61.3%
2002	9471	359	871	66	8175	2001 / 2	10933	359	1689	66	8819	2002	47557	61.6%
2003	9745	366	887	66	8426	2002 / 3	11239	366	1718	66	9089	2003	49182	61.8%
2004	10013	374	902	66	8671	2003 / 4	11546	374	1748	66	9358	2004	50815	62.0%
2005	10272	384	917	66	8905	2004 / 5	11843	384	1779	66	9614	2005	52347	62.2%
2006	10548	394	932	66	9156	2005 / 6	12162	394	1808	66	9894	2006	53978	62.3%
2007	10823	403	947	66	9407	2006 / 7	12486	403	1838	66	10179	2007	55618	62.4%
2008	11098	413	962	66	9657	2007 / 8	12816	413	1868	66	10469	2008	57263	62.4%
2009	11362	423	977	66	9896	2008 / 9	13133	423	1898	66	10746	2009	58833	62.5%
2010	11656	432	993	66	10165	2009 / 10	13487	432	1928	66	11061	2010	60565	62.5%
01-10 AAGR	2.66%					2.80% 01-10 AAGR	2.68%					01-10 AAGR	3.12%	
91-10 AAGR	3.35%					3.23% 91-10 AAGR	4.24%					91-10 AAGR	3.95%	

NOTE: COLUMN (2) = SUM OF COLUMNS (3) THROUGH (6). COLUMN (8) = SUM OF COLUMNS (9) THROUGH (12).
COLUMN (5) & (11), SELF-SERVICE GENERATION, ARE QF LOAD SERVED BY QF GENERATION.
COLUMN (6) & (12) = RECORDED DEMAND MINUS INTERRUPTIBLE SERVED MINUS L.M. SERVED.
1990 / 91 WINTER PEAK DEMAND DATA IS ACTUAL.

FLORIDA POWER CORPORATION

FUELS FORECAST (1991 - 2010)

BASE CASE OIL AND GAS PRICES

YEAR	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7 %			0.7 - 2.5 %			GREATER THAN 2.5 %			\$/BBL	c/MBTU	ESCALATION %	c/MBTU	ESCALATION %
	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %					
1991	21.00	355.90		20.00	317.50		17.00	269.80		25.20	434.50			
1992	22.00	372.90	4.8	20.00	317.50	0.0	17.00	269.80	0.0	26.46	456.21	5.0		
1993	24.00	406.80	9.1	21.00	333.30	5.0	18.00	285.70	5.9	28.56	492.41	7.9		
1994	27.00	457.60	12.5	23.00	365.10	9.5	20.50	325.40	13.9	31.08	535.86	8.8	285.00	15.8
1995	30.00	508.50	11.1	26.00	412.70	13.0	22.00	349.20	7.3	32.76	564.83	5.4	330.00	9.1
1996	32.00	542.40	6.7	28.00	444.40	7.7	23.00	365.10	4.6	34.86	601.03	6.4	360.00	11.1
1997	34.00	576.30	6.2	29.00	460.30	3.6	24.50	388.90	6.5	36.96	637.24	6.0	400.00	10.0
1998	36.00	610.20	5.9	31.00	492.10	6.9	26.57	421.70	8.4	39.06	673.45	5.7	440.00	13.6
1999	38.00	644.10	5.6	33.00	523.80	6.4	27.50	436.50	3.5	41.58	716.90	6.5	500.00	8.0
2000	42.00	711.90	10.5	34.00	539.70	3.0	29.00	460.30	5.5	43.68	753.10	5.0	540.00	5.1
2001	44.14	748.21	5.1	35.74	567.22	5.1	30.48	483.78	5.1	45.91	791.51	5.1	567.54	5.1
2002	46.40	786.37	5.1	37.56	596.15	5.1	32.03	508.45	5.1	48.25	831.88	5.1	596.48	5.1
2003	48.76	826.47	5.1	39.47	626.56	5.1	33.67	534.38	5.1	50.71	874.30	5.1	626.91	5.1
2004	51.25	868.62	5.1	41.49	658.51	5.1	35.38	561.63	5.1	53.30	918.89	5.1	658.88	5.1
2005	53.86	912.92	5.1	43.60	692.10	5.1	37.19	590.28	5.1	56.01	965.75	5.1	692.48	5.1
2006	56.61	959.48	5.1	45.83	727.39	5.1	39.08	620.38	5.1	58.87	1015.01	5.1	727.80	5.1
2007	59.50	1008.41	5.1	48.16	764.49	5.1	41.08	652.02	5.1	61.87	1066.77	5.1	764.91	5.1
2008	62.53	1059.84	5.1	50.62	803.48	5.1	43.17	685.27	5.1	65.03	1121.18	5.1	803.92	5.1
2009	65.72	1113.89	5.1	53.20	844.46	5.1	45.37	720.22	5.1	68.34	1178.36	5.1	844.93	5.1
2010	69.07	1170.70	5.1	55.91	887.52	5.1	47.69	756.95	5.1	71.83	1238.45	5.1	888.02	5.1
2011 & BEYOND														

NOTE: HEAT CONTENT LESS THAN 0.7% RESIDUAL OIL : 5.90 MBTU / BBL
HEAT CONTENT 0.7 > 2.5% RESIDUAL OIL : 6.30 MBTU / BBL
HEAT CONTENT DISTILLATE OIL : 5.80 MBTU / BBL

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 1.2

FUELS FORECAST (1991 - 2010)

PAGE 2 OF 8

LOW CASE OIL AND GAS PRICES

YEAR	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7 %			0.7 - 2.5 %			GREATER THAN 2.5 %			\$/BBL	c/MBTU	ESCALATION %	c/MBTU	ESCALATION %
	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %					
1991	17.00	288.10		14.00	222.20		13.00	206.40		21.82	376.19			
1992	17.50	296.60	3.0	14.50	230.20	3.6	13.50	214.30	3.8	22.67	390.86	3.9		
1993	18.00	305.10	2.9	15.00	238.10	3.4	14.00	222.20	3.7	23.55	406.11	3.9		
1994	18.50	313.60	2.8	15.50	246.00	3.3	14.50	230.20	3.6	24.47	421.94	3.9	230.00	
1995	19.00	322.00	2.7	16.00	254.00	3.3	15.00	238.10	3.4	25.50	439.66	4.2	235.00	2.2
1996	19.50	330.50	2.6	16.50	261.90	3.1	15.00	238.10	0.0	26.57	458.13	4.2	240.00	2.1
1997	20.00	339.00	2.6	17.00	269.80	3.0	15.25	242.10	1.7	27.69	477.37	4.2	245.00	2.1
1998	20.50	347.50	2.5	17.50	277.80	3.0	15.50	246.00	1.6	28.85	497.42	4.2	250.00	2.0
1999	21.00	355.90	2.4	18.00	285.70	2.8	15.50	246.00	0.0	30.06	518.31	4.2	255.00	2.0
2000	22.00	372.90	4.8	18.50	293.70	2.8	16.15	256.33	4.2	31.32	540.08	4.2	260.00	2.0
2001	22.93	388.56	4.2	19.28	306.04	4.2	16.83	267.10	4.2	32.64	562.76	4.2	270.92	4.2
2002	23.89	404.88	4.2	20.09	318.89	4.2	17.53	278.32	4.2	34.01	586.40	4.2	282.30	4.2
2003	24.89	421.89	4.2	20.93	332.28	4.2	18.27	290.01	4.2	35.44	611.03	4.2	294.16	4.2
2004	25.94	439.61	4.2	21.81	346.24	4.2	19.04	302.19	4.2	36.93	636.69	4.2	306.51	4.2
2005	27.03	458.07	4.2	22.73	360.78	4.2	19.84	314.88	4.2	38.48	663.43	4.2	319.38	4.2
2006	28.16	477.31	4.2	23.68	375.93	4.2	20.67	328.10	4.2	40.10	691.29	4.2	332.80	4.2
2007	29.34	497.35	4.2	24.68	391.72	4.2	21.54	341.88	4.2	41.78	720.33	4.2	346.77	4.2
2008	30.58	518.24	4.2	25.71	408.17	4.2	22.44	356.24	4.2	43.53	750.58	4.2	361.34	4.2
2009	31.86	540.01	4.2	26.80	425.32	4.2	23.39	371.20	4.2	45.36	782.11	4.2	376.52	4.2
2010	33.20	562.69	4.2	27.92	443.18	4.2	24.37	386.79	4.2	47.27	814.96	4.2	392.33	4.2
2011 & BEYOND			4.2			4.2			4.2			4.2		4.2

NOTE: HEAT CONTENT LESS THAN 0.7% RESIDUAL OIL : 5.90 MBTU / BBL
 HEAT CONTENT 0.7 - 2.5% RESIDUAL OIL : 6.30 MBTU / BBL
 HEAT CONTENT DISTILLATE OIL : 5.80 MBTU / BBL

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 1.2

PAGE 3 OF 8

FUELS FORECAST (1991 - 2010)

HIGH CASE OIL AND GAS PRICES

YEAR	RESIDUAL OIL (BY SULFUR CONTENT)									DISTILLATE OIL			NATURAL GAS	
	LESS THAN 0.7 %			0.7 - 2.5 %			GREATER THAN 2.5 %			\$/BBL	c/MBTU	ESCALATION %	c/MBTU	ESCALATION %
	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %	\$/BBL	c/MBTU	ESCALATION %					
1991	26.00	440.70		20.00	317.50		18.00	285.70		29.40	506.90			
1992	29.00	491.50	11.5	22.00	349.20	10.0	20.00	317.50	11.1	32.34	557.60	10.0		
1993	32.00	542.40	10.4	24.32	386.00	10.5	22.00	349.20	10.0	33.60	579.30	3.9		
1994	34.00	576.30	6.2	27.00	428.60	11.0	24.32	386.00	10.5	36.96	637.20	10.0	525.00	
1995	37.00	627.10	8.8	30.00	476.20	11.1	26.00	412.70	6.9	39.90	687.90	8.0	580.00	10.5
1996	43.00	728.80	16.2	35.00	555.50	16.7	30.00	476.20	15.4	44.10	760.30	10.5	638.00	10.0
1997	45.79	776.17	6.5	37.27	591.61	6.5	31.95	507.15	6.5	46.96	809.72	6.5	679.47	6.5
1998	48.77	826.62	6.5	39.69	630.06	6.5	34.03	540.12	6.5	50.02	862.35	6.5	723.64	6.5
1999	51.94	880.35	6.5	42.27	671.02	6.5	36.24	575.23	6.5	53.27	918.40	6.5	770.67	6.5
2000	55.32	937.58	6.5	45.02	714.63	6.5	38.59	612.62	6.5	56.73	978.10	6.5	820.77	6.5
2001	58.91	998.52	6.5	47.95	761.08	6.5	41.10	652.44	6.5	60.42	1041.68	6.5	874.12	6.5
2002	62.74	1063.42	6.5	51.06	810.55	6.5	43.78	694.84	6.5	64.34	1109.39	6.5	930.93	6.5
2003	66.82	1132.55	6.5	54.38	863.24	6.5	46.62	740.01	6.5	68.53	1181.50	6.5	991.44	6.5
2004	71.16	1206.16	6.5	57.92	919.35	6.5	49.65	788.11	6.5	72.98	1258.29	6.5	1055.89	6.5
2005	75.79	1284.56	6.5	61.68	979.11	6.5	52.88	839.34	6.5	77.72	1340.08	6.5	1124.52	6.5
2006	80.72	1368.06	6.5	65.69	1042.75	6.5	56.32	893.89	6.5	82.78	1427.19	6.5	1197.61	6.5
2007	85.96	1456.98	6.5	69.96	1110.53	6.5	59.98	952.00	6.5	88.16	1519.95	6.5	1275.46	6.5
2008	91.55	1551.69	6.5	74.51	1182.71	6.5	63.87	1013.88	6.5	93.89	1618.75	6.5	1358.36	6.5
2009	97.50	1652.54	6.5	79.35	1259.59	6.5	68.03	1079.78	6.5	99.99	1723.97	6.5	1446.66	6.5
2010	103.84	1759.96	6.5	84.51	1341.46	6.5	72.45	1149.96	6.5	106.49	1836.03	6.5	1540.69	6.5
2011 & BEYOND			6.5			6.5			6.5			6.5		6.5

NOTE: HEAT CONTENT LESS THAN 0.7% RESIDUAL OIL : 5.90 MBTU / BBL
 HEAT CONTENT 0.7 - 2.5% RESIDUAL OIL : 6.30 MBTU / BBL
 HEAT CONTENT DISTILLATE OIL : 5.80 MBTU / BBL

FLORIDA POWER CORPORATION

FUELS FORECAST (1991 - 2010)

BASE, LOW AND HIGH CASE
ORIMULSION PRICES

ORIMULSION - BASE PRICES

YEAR	ESCALATION		
	\$/BBL	c/MBTU	%
1991	8.80	200.00	2.0
1992	8.98	204.00	4.4
1993	9.37	213.00	3.8
1994	9.72	221.00	4.1
1995	10.12	230.00	5.1
1996	10.64	241.73	5.1
1997	11.18	254.06	5.1
1998	11.75	267.02	5.1
1999	12.35	280.63	5.1
2000	12.98	294.95	5.1
2001	13.64	309.99	5.1
2002	14.34	325.80	5.1
2003	15.07	342.41	5.1
2004	15.83	359.88	5.1
2005	16.64	378.23	5.1
2006	17.49	397.52	5.1
2007	18.38	417.79	5.1
2008	19.32	439.10	5.1
2009	20.31	461.49	5.1
2010	21.34	485.03	5.1
2011 & BEYOND			

ORIMULSION - LOW PRICES

ESCALATION		
\$/BBL	c/MBTU	%
7.52	171.00	
7.57	172.00	0.6
7.66	174.00	1.2
7.79	177.00	1.7
7.96	181.00	2.3
8.14	185.00	2.2
8.36	190.00	2.7
8.58	195.00	2.6
8.80	200.00	2.6
9.24	210.00	5.0
9.63	218.82	4.2
10.03	228.01	4.2
10.45	237.59	4.2
10.89	247.57	4.2
11.35	257.96	4.2
11.83	268.80	4.2
12.32	280.09	4.2
12.84	291.85	4.2
13.38	304.11	4.2
13.94	316.88	4.2

ORIMULSION - HIGH PRICES

ESCALATION		
\$/BBL	c/MBTU	%
11.00	250.00	
11.66	265.00	6.0
12.36	281.00	6.0
13.11	298.00	6.0
13.90	316.00	6.0
16.72	380.00	20.3
20.02	455.00	19.7
23.32	530.00	16.5
24.64	560.00	5.7
26.40	600.00	7.1
28.12	639.00	6.5
29.94	680.54	6.5
31.89	724.77	6.5
33.96	771.88	6.5
36.17	822.05	6.5
38.52	875.49	6.5
41.03	932.39	6.5
43.69	993.00	6.5
46.53	1057.54	6.5
49.56	1126.28	6.5

NOTE: HEAT CONTENT ORIMULSION

: 4.40 MBTU / BBL

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 1.2

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FUELS FORECAST (1991 - 2010)

BASE CASE COAL PRICES

YEAR	LOW SULFUR COAL LESS THAN 0.7 %			MEDIUM SULFUR COAL 0.7 - 1.5 %			HIGH SULFUR COAL GREATER THAN 1.5 %		
	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %
1991	52.38	204.60		47.34	190.90		43.00	172.00	
1992	53.15	207.60	1.5	50.05	201.80	5.7	43.00	172.00	0.0
1993	53.94	210.70	1.5	51.09	206.00	2.1	44.75	179.00	4.1
1994	55.22	215.70	2.4	52.60	212.10	3.0	46.25	185.00	3.4
1995	56.70	221.50	2.7	53.17	214.40	1.1	48.00	192.00	3.8
1996	59.60	232.80	5.1	55.88	225.33	5.1	50.45	201.79	5.1
1997	62.64	244.67	5.1	58.73	236.83	5.1	53.02	212.08	5.1
1998	65.83	257.15	5.1	61.73	248.90	5.1	55.72	222.90	5.1
1999	69.19	270.26	5.1	64.88	261.60	5.1	58.57	234.27	5.1
2000	72.72	284.05	5.1	68.19	274.94	5.1	61.55	246.22	5.1
2001	76.42	298.53	5.1	71.66	288.96	5.1	64.69	258.77	5.1
2002	80.32	313.76	5.1	75.32	303.70	5.1	67.99	271.97	5.1
2003	84.42	329.76	5.1	79.16	319.19	5.1	71.46	285.84	5.1
2004	88.72	346.58	5.1	83.20	335.47	5.1	75.10	300.42	5.1
2005	93.25	364.25	5.1	87.44	352.58	5.1	78.93	315.74	5.1
2006	98.00	382.83	5.1	91.90	370.56	5.1	82.96	331.84	5.1
2007	103.00	402.35	5.1	96.58	389.46	5.1	87.19	348.77	5.1
2008	108.26	422.87	5.1	101.51	409.32	5.1	91.64	366.55	5.1
2009	113.78	444.44	5.1	106.69	430.19	5.1	96.31	385.25	5.1
2010	119.58	467.10	5.1	112.13	452.13	5.1	101.22	404.89	5.1
2011 & BEYOND			5.1			5.1			5.1

NOTE: HEAT CONTENT LOW SULFUR COAL : 25.60 MBTU / TON
 HEAT CONTENT MEDIUM SULFUR COAL : 24.80 MBTU / TON
 HEAT CONTENT HIGH SULFUR COAL : 25.00 MBTU / TON

FLORIDA POWER CORPORATION

FUELS FORECAST (1991 - 2010)

LOW CASE COAL PRICES

YEAR	LOW SULFUR COAL LESS THAN 0.7 %			MEDIUM SULFUR COAL 0.7 - 1.5 %			HIGH SULFUR COAL GREATER THAN 1.5 %		
	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %
-----	51.99	203.10	0.0	47.73	190.90	4.3	42.00	168.00	0.0
1991	51.99	203.10	0.0	49.80	199.20	-0.6	42.00	168.00	1.2
1992	51.99	203.10	0.0	49.50	198.00	1.0	42.50	170.00	1.2
1993	51.99	203.10	0.0	50.00	200.00	0.5	43.00	172.00	2.3
1994	51.99	203.10	0.9	50.25	201.00	0.5	44.00	176.00	2.3
1995	52.48	205.00	1.0	50.50	202.00	0.5	45.00	180.00	2.2
1996	52.99	207.00	1.0	50.75	203.00	0.5	46.00	184.00	2.2
1997	53.50	209.00	0.9	51.00	204.00	0.5	47.00	188.00	2.1
1998	53.99	210.90	0.9	51.25	205.00	0.5	48.00	192.00	4.2
1999	54.50	212.90	0.9	51.50	206.00	4.2	50.00	200.00	4.2
2000	54.99	214.80	4.2	53.66	214.65	4.2	52.10	208.40	4.2
2001	57.30	223.82	4.2	55.92	223.67	4.2	54.29	217.15	4.2
2002	59.70	233.22	4.2	58.27	233.06	4.2	56.57	226.27	4.2
2003	62.21	243.02	4.2	60.71	242.85	4.2	58.94	235.78	4.2
2004	64.83	253.22	4.2	63.26	253.05	4.2	61.42	245.68	4.2
2005	67.55	263.86	4.2	65.92	263.68	4.2	64.00	256.00	4.2
2006	70.39	274.94	4.2	68.69	274.75	4.2	66.69	266.75	4.2
2007	73.34	286.49	4.2	71.57	286.29	4.2	69.49	277.95	4.2
2008	76.42	298.52	4.2	74.58	298.32	4.2	72.41	289.63	4.2
2009	79.63	311.06	4.2	77.71	310.85	4.2	75.45	301.79	4.2
2010	82.98	324.12	4.2						
2011 & BEYOND									

NOTE: HEAT CONTENT LOW SULFUR COAL
HEAT CONTENT MEDIUM SULFUR COAL
HEAT CONTENT HIGH SULFUR COAL

: 25.60 MBTU / TON
: 25.00 MBTU / TON
: 25.00 MBTU / TON

FLORIDA POWER CORPORATION

FUELS FORECAST (1991 - 2010)

HIGH CASE COAL PRICES

INDIVIDUAL UTILITY FORM 1
PAGE 7 OF 1

YEAR	LOW SULFUR COAL LESS THAN 0.7 %			MEDIUM SULFUR COAL 0.7 - 1.5 %			HIGH SULFUR COAL GREATER THAN 1.5 %		
	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %	\$/TON	c/MBTU	ESCALATION %
1991	52.72	212.60		48.98	204.10		52.01	216.70	
1992	58.06	234.10		53.88	224.50		52.01	216.70	
1993	62.50	252.00	10.1	58.03	241.80	10.0	55.01	229.20	0.0
1994	68.99	278.20	7.6	64.01	266.70	7.7	60.00	250.00	5.8
1995	73.48	296.28	10.4	68.17	284.04	10.3	64.99	270.80	9.1
1996	78.25	315.54	6.5	72.60	302.50	6.5	69.22	283.40	8.3
1997	83.34	336.05	6.5	77.32	322.16	6.5	73.72	307.15	6.5
1998	88.76	357.89	6.5	82.34	343.10	6.5	78.51	327.11	6.5
1999	94.53	381.16	6.5	87.70	365.40	6.5	83.61	348.38	6.5
2000	100.67	405.93	6.5	93.40	389.15	6.5	89.04	371.02	6.5
2001	107.22	432.32	6.5	99.47	414.45	6.5	94.83	395.14	6.5
2002	114.18	460.42	6.5	105.93	441.39	6.5	101.00	420.82	6.5
2003	121.61	490.35	6.5	112.82	470.08	6.5	107.56	448.17	6.5
2004	129.51	522.22	6.5	120.15	500.63	6.5	114.55	477.30	6.5
2005	137.93	556.16	6.5	127.96	533.17	6.5	122.00	508.33	6.5
2006	146.89	592.31	6.5	136.28	567.83	6.5	129.93	541.37	6.5
2007	156.44	630.82	6.5	145.14	604.74	6.5	138.37	576.56	6.5
2008	166.61	671.82	6.5	154.57	644.05	6.5	147.37	614.04	6.5
2009	177.44	715.49	6.5	164.62	685.91	6.5	156.95	653.95	6.5
2010	188.97	761.99	6.5	175.32	730.49	6.5	167.15	696.45	6.5
2011 & BEYOND									

NOTE: HEAT CONTENT LOW SULFUR COAL
HEAT CONTENT MEDIUM SULFUR COAL
HEAT CONTENT HIGH SULFUR COAL

: 24.80 MBTU / TON
: 24.00 MBTU / TON
: 24.00 MBTU / TON

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 1.2

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FUELS FORECAST (1991 - 2010)

NUCLEAR

YEAR	c/MBTU	ESCALATION %
1991	54.00	
1992	47.00	-12.96
1993	47.00	0.00
1994	51.92	10.47
1995	51.92	0.00
1996	57.35	10.46
1997	57.35	0.00
1998	63.35	10.46
1999	63.35	0.00
2000	69.97	10.45
2001	69.97	0.00
2002	77.27	10.43
2003	77.27	0.00
2004	85.37	10.48
2005	85.37	0.00
2006	94.31	10.47
2007	94.31	0.00
2008	104.17	10.45
2009	104.17	0.00
2010	115.07	10.46

FIRM PURCHASES

YEAR	\$/MWh	ESCALATION %
1991		
1992		
1993		
1994	23.44	
1995	24.27	3.54
1996	25.18	3.75
1997	26.91	6.87
1998	28.37	5.43
1999	29.57	4.23
2000	30.59	3.45
2001	32.62	6.64
2002	34.23	4.94
2003	35.88	4.82
2004	37.75	5.21
2005	39.73	5.25
2006	41.50	4.46
2007	43.45	4.70
2008	45.33	4.33
2009	47.85	5.56
2010	48.15	0.63

INDIVIDUAL UTILITY FORM 1.3

FLORIDA POWER CORPORATION

ECONOMIC ASSUMPTIONS

BASE CASE

AFUDC RATE

9.46 %

CAPITALIZATION RATIOS

DEBT	45.0 %
PREFERRED	8.0 %
EQUITY	47.0 %

DISCOUNT RATE

9.46 %

RATE OF RETURN

DEBT	9.5 %
PREFERRED	8.5 %
EQUITY	13.0 %

TAX DEPRECIATION LIFE

15 YEARS

INCOME TAX RATE

STATE	5.50 %
* FEDERAL	32.13 %
EFFECTIVE	37.63 %

INVESTMENT TAX CREDIT

0.00 %

* STATE INCOME TAXES ARE DEDUCTIBLE FOR FEDERAL TAX PURPOSES AND
THUS EFFECTIVELY REDUCE THE FEDERAL TAX RATE FROM 34 % TO 32.13 %.

FLORIDA POWER CORPORATION
SUMMARY OF NEW UNIT ADDITIONS

INDIVIDUAL UTILITY FORM 2.1

BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)
			CONSTRUCTION	NET	
	UNIT	FUEL	START	SUMMER	WINTER
YEAR	TYPE		MO/YR	(MW)	(MW)
----	----	----	-----	-----	-----
1992	GT	F02	11/1990	304	364
1993	GT	F02	11/1991	304	364
1993	GT	NG	11/1991	37	40
1998	CC	NG	11/1995	200	235
1999	CC	NG	11/1996	200	235
1999	CC	NG	11/1996	200	235
2000	CC	NG	11/1997	200	235

FLORIDA POWER CORPORATION
SUMMARY OF CAPACITY, DEMAND AND RESERVE MARGIN
AT TIME OF SUMMER PEAK

BASE CASE

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)					
YEAR	INSTALLED CAPACITY		CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED	TOTAL AVAILABLE CAPACITY (MW)	COINCIDENT FIRM PEAK DEMAND (MW)	RESERVE MARGIN		L.O.L.P. ISOLATED (DAYS/YR)	L.O.L.P. NET (DAYS/YR)					
	EXISTING & CERTIFIED	FUTURE ADDITIONS		FIRM NET TO GRID FROM QF (MW)											
							(MW)	% OF PEAK							
1991	6,192.0	0.0	400.0	135.0	6,727.0	5,559.0	1,168.0	21.0%	1.622	0.368					
1992	6,207.0	0.0	400.0	168.0	6,775.0	5,809.0	966.0	16.6%	3.975	1.041					
1993	6,207.0	304.0	400.0	356.0	7,267.0	6,046.0	1,221.0	20.2%	2.138	0.364					
1994	6,207.0	648.0	400.0	590.0	7,845.0	6,223.0	1,622.0	26.1%	0.297	0.039					
1995	6,207.0	648.0	400.0	624.0	7,879.0	6,418.0	1,461.0	22.8%	0.548	0.082					
1996	6,207.0	648.0	400.0	769.0	8,024.0	6,575.0	1,449.0	22.0%	0.659	0.118					
1997	6,207.0	648.0	400.0	769.0	8,024.0	6,727.0	1,297.0	19.3%	0.113	0.012					
1998	6,207.0	648.0	400.0	919.0	8,174.0	6,873.0	1,301.0	18.9%	0.124	0.011					
1999	6,207.0	848.0	400.0	919.0	8,374.0	7,019.0	1,355.0	19.3%	0.094	0.009					
2000	5,978.0	1,248.0	400.0	919.0	8,545.0	7,188.0	1,357.0	18.9%	0.096	0.006					
2001	5,928.0	1,448.0	400.0	919.0	8,695.0	7,365.0	1,330.0	18.1%	0.124	0.013					

FLORIDA POWER CORPORATION
SUMMARY OF CAPACITY, DEMAND AND RESERVE MARGIN
AT TIME OF WINTER PEAK

(1)	(2)	(3)	(4)	BASE CASE		(7)	(8)	(9)
				(5)	(6)			
				CONTRACTED FIRM INTERCHANGE (MW)	PROJECTED FIRM NET TO GRID FROM QF (MW)	TOTAL AVAILABLE CAPACITY (MW)	COINCIDENT FIRM PEAK DEMAND (MW)	RESERVE MARGIN (MW) % OF PEAK
YEAR	EXISTING & CERTIFIED	FUTURE ADDITIONS						
1990 / 91	6,571.0	0.0	400.0	112.0	7,083.0	5,834.0	1,249.0	21.4%
1991 / 92	6,621.0	0.0	400.0	168.0	7,189.0	6,681.0	508.0	7.6%
1992 / 93	6,621.0	364.0	400.0	203.0	7,588.0	6,921.0	667.0	9.6%
1993 / 94	6,621.0	768.0	400.0	590.0	8,379.0	7,047.0	1,332.0	18.9%
1994 / 95	6,621.0	768.0	400.0	624.0	8,413.0	7,172.0	1,241.0	17.3%
1995 / 96	6,621.0	768.0	400.0	769.0	8,558.0	7,300.0	1,258.0	17.2%
1996 / 97	6,621.0	768.0	400.0	769.0	8,558.0	7,422.0	1,136.0	15.3%
1997 / 98	6,621.0	768.0	400.0	919.0	8,708.0	7,536.0	1,172.0	15.6%
1998 / 99	6,621.0	1,003.0	400.0	919.0	8,943.0	7,647.0	1,296.0	16.9%
1999 / 0	6,372.0	1,473.0	400.0	919.0	9,164.0	7,762.0	1,402.0	18.1%
2000 / 1	6,312.0	1,708.0	400.0	919.0	9,339.0	7,950.0	1,389.0	17.5%

ABBREVIATIONS :

Fuel Transportation Method

PL	-	Pipeline
RR	-	Railroad
TK	-	Truck
WA	-	Water
UN	-	Unknown

Power and Energy

KW	-	Kilowatt
KWh	-	Kilowatt-hour
MW	-	Megawatt (1000 KW)
MWh	-	Megawatt-hour (1000 KWh)
GW	-	Gigawatt (1000 MW)
GWh	-	Gigawatt-hour (1000 MWh)

Status of Generation Facilities

A	-	Capability increase.
C	-	Conversion from oil to coal.
CA	-	Conversion to alternate fuel.
CG	-	Conversion to gas.
D	-	Capability decrease.
L	-	Regulatory approval pending; not under construction.
M	-	Cold standby, reserve shutdown.
P	-	Planned, but not authorized by utility.
R	-	To be retired.
S	-	Returned from cold standby or reserve shutdown.
T	-	Regulatory approval received or not required;
U	-	not under construction.
V	-	Under construction; less than 50 % completed.
	-	Under construction; more than 50 % completed.

Types of Fuel

ALT	-	Alternate Fuel
BIT	-	Bituminous Coal
F02	-	No. 2 fuel oil (distillate)
F06	-	No. 6 fuel oil (heavy)
NG	-	Natural Gas
SW	-	Solid Waste
UR	-	Nuclear (uranium)
WA	-	Water
WH	-	Waste Heat
UN	-	Unknown

Types of Generation Units

CC	-	Combined Cycle
CCT	-	Combined Cycle, Combustion Turbine
CCW	-	Combined Cycle, Waste Heat
D	-	Diesel
GT	-	Combustion Turbine (Gas Turbine)
HRS	-	Heat Recovery Steam Generator
HRSG	-	Hydro
HY	-	Integrated Coal Gasification Combined Cycle
IGCC	-	Steam Power (Nuclear)
NP	-	Steam Turbine (Non-Nuclear)
ST	-	Unknown
UN	-	Unknown

ABBREVIATIONS :

Type of Qualifying Facility

COG	-	Cogenerator
SPP	-	Small Power Producer
SSG	-	Self Service Generation

Qualifying Facility Fuel Type

BIO	-	Biomass
C	-	Coal
F02	-	No. 2 fuel oil (distillate)
F06	-	No. 6 fuel oil (heavy)
HY	-	Hydro
MG	-	Methane Gas
NG	-	Natural Gas
OTH	-	Other
PG	-	Propane Gas
PT	-	Peat
SW	-	Solid Waste
WD	-	Wood
WH	-	Waste Heat
MSW	-	Municipal Solid Waste

Qualifying Facility Status

C	-	Under contract for the delivery of energy and/or capacity to the utility.
NC	-	Not under contract for the delivery of energy and/or capacity to the utility.

Scheduled Interchange/Purchased Power Agreements

FR	-	Full requirement service agreement.
PR	-	Partial requirement service agreement.
Schd D	-	Long term firm capacity and energy interchange agreement.
Schd E	-	Non-firm capacity and energy interchange agreement.
Schd F	-	Long-term non-firm capacity and energy interchange agreement.
Schd G	-	Back up reserve service.
Schd J	-	Contract which the terms and conditions are negotiated yearly.
UPS	-	Unit Power Sale.

DEFINITIONS :

AAGR - in percent, is the calculated Average Annual Growth Rate.

AVERAGE DEMAND - obtained by dividing the energy used over a period of time by the number of hours in that period.

INTERRUPTIBLE LOAD - load which may be disconnected at the supplier's discretion.

LOAD FACTOR - in percent, calculated by multiplying the NEL (MWH) by 100 and dividing it by the product of the peak demand (MW) and the number of hours in the year.

NET CAPABILITY OR NET CAPACITY - the continuous gross capacity, less the power required by all auxiliaries associated with the unit, or the capacity as specified by "SERC Guideline Number 2 for Uniform Generator Rating for Reporting".

NET ENERGY FOR LOAD (NEL) - the net system generation plus interchange received minus interchange delivered.

PEAK DEMAND OR PEAK LOAD - the net 60-minute integrated demand, actual or adjusted. Forecasted loads assume normal weather conditions.

PENINSULAR FLORIDA - geographically, those Florida utilities located east of the Apalachicola River.

QUALIFYING FACILITY (QF) - the cogenerator or small power producer which meets FERC criteria for a qualifying facility.

SALES FOR RESALE - energy sales to other electric utilities.

STATE OF FLORIDA - utilities in Peninsular Florida plus Gulf Power Company, West Florida Electric Cooperative, Choctawhatchee Electric Cooperative, Escambia River Electric Cooperative, Gulf Coast Electric Cooperative and Alabama Electric Cooperative.

SUMMER - May 1 through October 31 of the year being studied.

WINTER - November 1 of the previous year through March 31 of the year being studied.

YEAR - the calendar year, January 1 through December 31. Unless otherwise indicated, this is the year used for historical and forecast data.

FLORIDA POWER CORPORATION
HISTORY AND FORECAST
ENERGY USE BY CUSTOMER TYPE - GWH
BASE (MOST PROBABLE) FORECAST

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
YEAR	RURAL & RESIDENTIAL			COMMERCIAL			INDUSTRIAL			STREET & HIGHWAY LIGHTING	OTHER SALES	TOTAL SALES	RESALE	UTILITY USE & LOSSES	NEL	SERVICE AREA POPULATION
	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	CUSTOMERS	KWH/CUST	GWH	GWH	GWH	GWH	GWH	GWH	
1981	7752	720590	10758	3735	74413	50195	3288	2241	1467347	22	1017	15814	3642	1467	20924	1849551
1982	7425	745155	9964	3895	76226	51101	2716	2336	1162475	19	1076	15131	3630	1337	20098	1899836
1983	8010	771047	10388	4119	81249	50691	2701	2409	1121221	16	1127	15972	3848	1912	21732	1948454
1984	8554	804092	10638	4548	86803	52391	2989	2540	1176765	16	1173	17279	2114	1315	20708	2027893
1985	9175	838671	10940	5107	91817	55617	3166	2611	1212567	17	1251	18716	1757	1904	22377	2108148
1986	9819	872441	11255	5573	96843	57547	3122	2705	1154272	18	1301	19834	1408	1444	22685	2184085
1987	10319	908640	11356	6016	102657	58607	3349	2877	1164187	19	1336	21040	1441	1812	24292	2265656
1988	11066	941439	11754	6479	106899	60612	3681	2942	1251063	19	1447	22692	1432	1724	25848	2337306
1989	11787	977449	12059	6990	111079	62926	3766	3021	126649	20	1561	24123	1529	2194	27847	2413913
1990	12416	1007806	12319	7329	113595	64516	3456	3115	1109376	21	1658	24878	1548	1379	27805	2485078
1981-'90 % AAGR	5.37%	3.80%	1.52%	7.78%	4.81%	2.83%	0.55%	3.73%	-3.06%	-0.51%	5.58%	5.16%	-9.07%	-0.69%	3.21%	3.34%
1991	12349	1032836	11957	7568	115044	65781	3379	3166	1067357	23	1715	25035	1487	2130	28652	2554030
1992	13292	1060280	12536	7914	118069	67025	3605	3267	1103590	25	1776	26612	1761	2099	28652	2620660
1993	13801	1091872	12640	8332	122197	68182	3711	3363	1103512	26	1864	27734	2100	2203	32037	2684858
1994	14345	1124254	12760	8769	126525	69310	3895	3459	1125907	27	1925	28962	2329	2301	33592	2746514
1995	14870	1155420	12870	9196	130704	70361	4242	3555	1193149	29	1984	30321	2537	2386	35244	2805519
1996	15379	1185344	12974	9609	134686	71343	4335	3651	1187356	31	2040	31394	2738	2466	36597	2851827
1997	15851	1214222	13054	10004	138465	72252	4422	3747	1180239	32	2093	32403	2946	2544	37893	2915659
1998	16291	1242202	13115	10385	142128	73071	4502	3843	1171437	34	2143	33355	3174	2620	39149	2967298
1999	16713	1269401	13166	10760	145689	73854	4575	3939	1161497	36	2191	34274	3417	2694	40386	3017031
2000	17113	1295936	13205	11127	149164	74594	4651	4035	1152663	37	2237	35164	3679	2768	41611	3065142
1991-'00 % AAGR	3.69%	2.55%	1.11%	4.38%	2.93%	1.41%	3.61%	2.73%	0.86%	5.55%	2.99%	3.85%	10.58%	2.96%	4.23%	2.05%
2001	17506	1321916	13243	11488	152566	75299	4733	4131	1145622	39	2281	36046	3927	2841	42814	3111895
2002	17901	1347415	13285	11845	155906	75977	4817	4227	1139628	40	2324	36928	4185	2915	44028	3157474
2003	18297	1372500	13331	12196	159191	76615	4902	4323	1133934	42	2367	37804	4450	2989	45243	3202040
2004	18693	1397238	13378	12543	162431	77218	4983	4419	1127597	43	2408	38669	4729	3062	46461	3245757
2005	19085	1421694	13424	12882	165634	77776	5055	4515	1119544	44	2448	39515	5001	3135	47651	3288785
2006	19483	1445888	13475	13215	168803	78286	5127	4611	1111980	46	2488	40359	5285	3208	48852	3331288
2007	19880	1469840	13525	13539	171940	78745	5207	4707	1106213	47	2526	41199	5575	3281	50055	3373427
2008	20280	1493570	13578	13856	175048	79153	5287	4803	1100766	49	2563	42034	5882	3355	51271	3415366
2009	20683	1517088	13633	14163	178128	79512	5365	4899	1095201	50	2599	42860	6175	3427	52462	3457266
2010	21085	1540404	13688	14462	181182	79818	5437	4995	1088395	51	2634	43668	6483	3499	53651	3499289
2001-'10 % AAGR	2.09%	1.71%	0.37%	2.59%	1.93%	0.65%	1.55%	2.13%	-0.57%	3.21%	1.61%	2.15%	5.73%	2.34%	2.54%	1.31%
1991-'10 % AAGR	2.86%	2.13%	0.71%	3.47%	2.42%	1.02%	2.53%	2.43%	0.10%	4.35%	2.28%	2.97%	8.06%	2.65%	3.36%	1.67%

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 5.5
PAGE 1 OF 6

SUMMER PEAK DEMAND AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT SUPPLYING UTILITY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	FIRM SUMMER PEAK DEMAND	SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	PURCHASING UTILITY COINCIDENT SUMMER PEAK DEMAND (MW)																					
YEAR			ALA	BAR	BUS	CHA	FMD	FMP	HAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	STC	WAU	WIL
1990	5374	4784	0	45	0	6	8	110	3	0	0	0	15	0	4	0	1	22	34	0	327	0	10	5
1991	5559	4784	0	48	0	7	9	142	3	43	0	0	16	0	4	0	1	24	52	0	370	39	11	5
1992	5809	4887	0	50	0	7	9	170	3	47	0	0	17	35	5	0	1	25	60	0	431	46	11	6
1993	6046	5007	0	51	0	7	9	180	3	72	0	0	17	35	5	0	1	26	85	0	477	53	12	6
1994	6223	5124	0	53	0	7	10	180	4	77	0	0	18	35	5	0	1	26	82	0	526	57	12	6
1995	6418	5231	0	55	0	7	10	190	4	83	0	0	19	35	5	0	1	27	90	0	582	61	12	6
1996	6575	5333	0	57	0	8	10	190	4	83	0	0	19	35	5	0	1	28	90	0	632	61	13	6
1997	6727	5429	0	58	0	8	11	190	4	83	0	0	20	35	5	0	1	29	90	0	684	61	13	7
1998	6873	5519	0	60	0	8	11	190	4	83	0	0	20	35	5	0	1	30	90	0	736	61	13	7
1999	7019	5606	0	62	0	8	11	190	4	83	0	0	21	35	6	0	1	31	90	0	790	61	14	7
2000	7188	5717	0	63	0	9	11	190	4	83	0	0	21	35	6	0	1	31	90	0	844	61	14	7
2001	7365	5840	0	65	0	9	12	190	4	83	0	0	22	35	6	0	1	32	90	0	894	61	15	7
2002	7542	5961	0	67	0	9	12	190	5	83	0	0	23	35	6	0	1	33	90	0	945	61	15	8
2003	7721	6083	0	68	0	9	12	190	5	83	0	0	23	35	6	0	1	34	90	0	998	61	15	8
2004	7895	6201	0	70	0	9	13	190	5	83	0	0	24	35	6	0	1	34	90	0	1050	61	16	8
2005	8071	6318	0	71	0	10	13	190	5	83	0	0	24	35	6	0	1	35	90	0	1104	61	16	8
2006	8248	6437	0	73	0	10	13	190	5	83	0	0	25	35	7	0	1	36	90	0	1158	61	16	8
2007	8424	6555	0	75	0	10	13	190	5	83	0	0	25	35	7	0	1	37	90	0	1211	61	17	8
2008	8601	6674	0	76	0	10	14	190	5	83	0	0	26	35	7	0	1	38	90	0	1265	61	17	9
2009	8778	6793	0	78	0	11	14	190	5	83	0	0	26	35	7	0	1	39	90	0	1319	61	18	9
2010	8955	6910	0	80	0	11	14	190	5	83	0	0	27	35	7	0	1	40	90	0	1374	61	18	9

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (24).

ALA-ALACHUA
BAR-BARTOW
BUS-BUSHNELL

CHA-CHATTAHOOCHEE
FMD-FT. MEADE
FMP-FMPPA

HAV-HAVANA
KIS-KISSIMEE
LEE-LEESBURG

LKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SMYRNA

NEW-NEWMERRY
OCA-OCALA
OUC-ORLANDO

QUI-QUINCY
RCU-REEDY CREEK
SEB-SEBRING

SEC-SECI
STC-ST. CLOUD
WAU-WAUCHULA

WIL-WILLISTON

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 5.5
PAGE 2 OF 6SUMMER PEAK DEMAND AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT PURCHASING UTILITY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
FIRM SUMMER PEAK DEMAND	SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	PURCHASING UTILITY COINCIDENT SUMMER PEAK DEMAND (MW)																					
YEAR		ALA	BAR	BUS	CHA	FMD	FMP	HAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	STC	WAU	WIL
1990																							
1991																							
1992																							
1993																							
1994																							
1995																							
1996																							
1997																							
1998																							
1999																							
2000																							
2001																							
2002																							
2003																							
2004																							
2005																							
2006																							
2007																							
2008																							
2009																							
2010																							

***** NOT APPLICABLE *****

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (24).

ALA-ALACHUA
BAR-BARTON
BUS-BUSHNELLCHA-CHATTANOOCHEE
FMD-FT. MEADE
FMP-FMPAHAV-HAVANA
KIS-KISSIMMEE
LEE-LEESBURGLKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SHYRNANEW-NEWBERRY
OCA-OCALA
OUC-ORLANDOQUI-QUINCY
RCU-REEDY CREEK
SEB-SEBRINGSEC-SEC1
STC-ST. CLOUD
WAU-WAUCHULA

WIL-WILLISTON

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 5.5
PAGE 3 OF 6WINTER PEAK DEMAND AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT SUPPLYING UTILITY

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
	FIRM WINTER PEAK DEMAND	SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	PURCHASING UTILITY COINCIDENT WINTER PEAK DEMAND (MW)																					
YEAR			ALA	BAR	BUS	CHA	FMD	FMP	HAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	STC	WAU	WIL
1990 / 91	5370	4671	0	49	0	6	8	56	3	0	0	0	15	0	3	0	2	11	1	0	532	0	10	3
1991 / 92	6681	5503	0	58	0	7	10	170	4	47	0	0	18	0	4	0	2	14	60	0	722	46	12	4
1992 / 93	6921	5570	0	60	0	8	10	180	4	72	0	0	19	35	4	0	2	14	85	0	789	53	13	4
1993 / 94	7047	5626	0	62	0	8	10	180	4	77	0	0	20	35	4	0	2	14	82	0	849	57	13	4
1994 / 95	7172	5643	0	64	0	8	11	190	4	83	0	0	20	35	4	0	2	15	90	0	925	61	13	4
1995 / 96	7300	5710	0	66	0	8	11	190	4	83	0	0	21	35	4	0	2	15	90	0	982	61	14	4
1996 / 97	7422	5769	0	67	0	9	11	190	4	83	0	0	21	35	4	0	2	16	90	0	1041	61	14	4
1997 / 98	7536	5820	0	69	0	9	12	190	4	83	0	0	22	35	4	0	2	16	90	0	1100	61	15	4
1998 / 99	7647	5866	0	71	0	9	12	190	4	83	0	0	22	35	4	0	2	16	90	0	1161	61	15	4
1999 / 0	7762	5914	0	73	0	9	12	190	5	83	0	0	23	35	5	0	2	17	90	0	1224	61	15	5
2000 / 1	7950	6038	0	75	0	9	13	190	5	83	0	0	23	35	5	0	2	17	90	0	1284	61	16	5
2001 / 2	8138	6161	0	76	0	10	13	190	5	83	0	0	24	35	5	0	2	18	90	0	1345	61	16	5
2002 / 3	8331	6286	0	79	0	10	13	190	5	83	0	0	25	35	5	0	2	18	90	0	1408	61	16	5
2003 / 4	8523	6409	0	81	0	10	13	190	5	83	0	0	25	35	5	0	2	19	90	0	1473	61	17	5
2004 / 5	8716	6533	0	82	0	10	14	190	5	83	0	0	26	35	5	0	2	19	90	0	1538	61	17	5
2005 / 6	8916	6658	0	84	0	11	14	190	5	83	0	0	26	35	5	0	2	19	90	0	1609	61	18	5
2006 / 7	9119	6786	0	86	0	11	14	190	5	83	0	0	27	35	5	0	2	20	90	0	1680	61	18	5
2007 / 8	9328	6917	0	88	0	11	15	190	6	83	0	0	28	35	6	0	2	20	90	0	1754	61	18	6
2008 / 9	9536	7048	0	90	0	11	15	190	6	83	0	0	28	35	6	0	2	21	90	0	1827	61	19	6
2009 / 10	9749	7181	0	91	0	11	15	190	6	83	0	0	29	35	6	0	2	21	90	0	1903	61	19	6
2010 / 11	9959	7312	0	93	0	12	16	190	6	83	0	0	29	35	6	0	2	21	90	0	1978	61	19	6

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (24).

ALA-ALACHUA
BAR-BARTOW
BUS-BUSHNELLCHA-CHATTANOOCHEE
FMD-FT. MEADE
FMP-FMPPAHAV-HAVANA
KIS-KISSIMMEE
LEE-LEESBURGLKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SHYRNANEW-NEWBERRY
OCA-OCALA
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RCU-REEDY CREEK
SEB-SEBRINGSEC-SECI
STC-ST. CLOUD
WAU-WAUCHULA

WIL-WILLISTON

FLORIDA POWER CORPORATION

WINTER PEAK DEMAND AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT PURCHASING UTILITY

WINTER PEAK DEMAND AND ITS COMPONENTS FORM FOR A PARTIAL OR FULL REQUIREMENT PURCHASING UTILITY																								
YEAR	(1) FIRM WINTER PEAK DEMAND	(2) SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)
			PURCHASING UTILITY COINCIDENT WINTER PEAK DEMAND (MW)																					
			ALA	BAR	BUS	CHA	FMD	FMP	HAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	STC	WAU	WIL
1990 / 91																								
1991 / 92																								
1992 / 93																								
1993 / 94																								
1994 / 95																								
1995 / 96																								
1996 / 97																								
1997 / 98																								
1998 / 99																								
1999 / 0																								
2000 / 1																								
2001 / 2																								
2002 / 3																								
2003 / 4																								
2004 / 5																								
2005 / 6																								
2006 / 7																								
2007 / 8																								
2008 / 9																								
2009 / 10																								
2010 / 11																								

***** NOT APPLICABLE *****

THROUGH COLUMN (24).

WIL-WILLISTON

***** NOT APPLICABLE *****

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (24).

ALA-ALACHUA
BAR-BARTOW
BUS-BUSHNELLCHA-CHATTAHOOCHEE
FMD-FT. MEADE
FMP-FMPAHAV-HAVANA
KIS-KISSIMMEE
LEE-LEESBURGLKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SMYRNANEW-NEWBERRY
OCA-OCALA
OUC-ORLANDOQUI-QUINCY
RCU-REEDY CREEK
SEB-SEBRINGSEC-SECI
STC-ST. CLOUD
WAU-WAUCHULA

WIL-WILLISTON

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 5.5

PAGE 5 OF 6

NET ENERGY FOR LOAD AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT SUPPLYING UTILITY

YEAR	(1) OFFICIAL NET ENERGY FOR LOAD GWH	(2) SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
			FULL OR PARTIAL REQUIREMENTS WHOLESale DELIVERY (GWH)																						
			ALA	BAR	BUS	CHA	FMD	FMP	NAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	SPA	STC	WAU	WIL
1990	27805	26257	0	248	0	31	39	455	19	0	0	0	67	0	25	0	9	93	162	0	285	36	0	55	24
1991	28652	27165	0	249	0	31	39	363	19	4	0	0	67	0	25	0	9	93	101	0	256	30	121	55	24
1992	30472	28711	0	262	0	33	41	376	20	19	0	0	71	18	26	0	10	98	139	0	408	30	126	58	25
1993	32037	29937	0	272	0	34	43	397	21	108	0	0	74	33	27	0	10	102	193	0	524	30	146	60	26
1994	33592	31262	0	282	0	35	44	420	22	131	0	0	76	33	28	0	10	106	194	0	652	30	176	63	27
1995	35244	32707	0	292	0	37	46	442	22	122	0	0	79	33	30	0	11	110	209	0	802	30	180	65	28
1996	36597	33858	0	302	0	38	47	464	23	121	0	0	82	33	30	0	11	113	212	0	957	30	180	67	29
1997	37893	34946	0	311	0	39	49	484	24	121	0	0	84	33	31	0	11	117	212	0	1122	30	180	69	30
1998	39149	35974	0	320	0	40	50	504	25	121	0	0	86	33	32	0	12	120	212	0	1309	30	180	71	31
1999	40386	36968	0	328	0	41	52	523	25	121	0	0	89	33	33	0	12	123	212	0	1512	30	180	73	32
2000	41611	37932	0	336	0	42	53	542	26	121	0	0	91	33	34	0	12	126	212	0	1734	30	180	75	33
2001	42814	38886	0	344	0	43	54	560	26	121	0	0	93	33	35	0	13	129	212	0	1945	30	180	76	33
2002	44028	39842	0	353	0	44	55	578	27	121	0	0	95	33	36	0	13	132	212	0	2165	30	180	78	34
2003	45243	40791	0	361	0	45	57	596	28	121	0	0	97	33	36	0	13	135	212	0	2393	30	180	80	35
2004	46461	41730	0	368	0	46	58	614	28	121	0	0	100	33	37	0	13	138	212	0	2635	30	180	82	36
2005	47651	42650	0	376	0	47	59	631	29	121	0	0	102	33	38	0	14	141	212	0	2869	30	180	83	36
2006	48852	43567	0	384	0	48	60	648	29	121	0	0	104	33	39	0	14	144	212	0	3117	30	180	85	37
2007	50055	44480	0	391	0	49	62	665	30	121	0	0	106	33	39	0	14	147	212	0	3372	30	180	87	38
2008	51271	45388	0	399	0	50	63	682	31	121	0	0	108	33	40	0	15	150	212	0	3644	30	180	89	39
2009	52462	46286	0	406	0	51	64	698	31	121	0	0	110	33	41	0	15	152	212	0	3903	30	180	90	39
2010	53651	47166	0	413	0	52	65	715	32	121	0	0	112	33	42	0	15	155	212	0	4178	30	180	92	40

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (25).

ALA-ALACHUA
BAR-BARTOW
BUS-BUSHNELLCHA-CHATTANOOCHEE
FMD-FT. MEADE
FMP-FMPANAV-NAVANA
KIS-KISSIMMEE
LEE-LEESBURGLKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SMYRNANEW-NEWBERRY
OCA-OCALA
OUC-ORLANDOQUI-QUINCY
RCU-REEDY CREEK
SEB-SEBRINGSEC-SECI
SPA-SEPA
STC-ST. CLOUDWAU-WAUCHULA
WIL-WILLISTON

FLORIDA POWER CORPORATION
NET ENERGY FOR LOAD AND ITS COMPONENTS
FORM FOR A PARTIAL OR FULL REQUIREMENT PURCHASING UTILITY

YEAR	(1) OFFICIAL NET ENERGY FOR LOAD GWH	(2) SERVED BY OWN GENERATION AND FIRM INTERCHANGE PURCHASES	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
			FULL OR PARTIAL REQUIREMENTS WHOLESale DELIVERY (GWH)																						
			ALA	BAR	BUS	CHA	FMD	FMP	HAV	KIS	LEE	LKH	MTD	NSB	NEW	OCA	OUC	QUI	RCU	SEB	SEC	SPA	STC	WAU	WIL
1990																									
1991																									
1992																									
1993																									
1994																									
1995																									
1996																									
1997																									
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1999																									
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2001																									
2002																									
2003																									
2004																									
2005																									
2006																									
2007																									
2008																									
2009																									
2010																									

***** NOT APPLICABLE *****

NOTE : COLUMN (1) = TOTAL OF COLUMN (2) THROUGH COLUMN (25).

ALA-ALACHUA
BAR-BARTOW
BUS-BUSHNELL

CHA-CHATTAHOOCHEE
FMD-FT. MEADE
FMP-FMPA

HAV-HAVANA
KIS-KISSIMMEE
LEE-LEESBURG

LKH-LK. HELEN
MTD-MT. DORA
NSB-NEW SMYRNA

NEW-NEWBERRY
OCA-OCALA
OUC-ORLANDO

QUI-QUINCY
RCU-REEDY CREEK
SEB-SEBRING

SEC-SECI
SPA-SEPA
STC-ST. CLOUD

WAU-WAUCHULA
WIL-WILLISTON

FLORIDA POWER CORPORATION

EXISTING GENERATING CAPABILITY

FLORIDA POWER												
EXISTING GENERATING CAPABILITY												
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
PLANT NAME	UNIT NO.	LOC.	FUEL		FUEL TRANSPORTATION		COMMERCIAL IN-SERVICE (MO/YR)	EXPECTED RETRMENT (MO/YR)	GEN MAX (kW)	NET CAPABILITY - MW		
			UNIT TYPE	PRIMARY ALTERNATE	PRIMARY ALTERNATE	SUMMER				WINTER		
ANCLOTE	1	PASCO CO.	ST	F06								
	2	SECT. 33, 34 T26S, R15E	ST	F06			PL	10/1974 10/1978	556,200 556,200	973 503	1019 517	
AVON PARK	P1-2	HIGHLANDS CO.	GT	F02			TK	12/1968	12/2000	67,600	50	60
BARTOW	1	PINELLAS CO.	ST	F06			WA	09/1958		127,500	610	654
	2	SECT. 20, 21, 22	ST	F06		NG	WA	08/1961		127,500	107	108
	3	T30S, R16E	ST	F06			WA	07/1963		239,400	117	119
	P1-4		GT	F02			WA	06/1972		222,800	210	215
BAYBORO	P1-4	PINELLAS CO.	GT	F02						226,800	184	216
		SECT. 30 T31S, R17E										
CRYSTAL RIVER	1	CITRUS CO.	ST	BIT			WA&RR	10/1966		440,500	2957	3020
	2	SECT. 33	ST	BIT			WA&RR	11/1969		523,800	372	373
	3	T17S, R16E	HP	UR			WA&RR	03/1977		801,400	468	469
	4		ST	BIT			WA&RR	12/1982		739,300	723	744
	5		ST	BIT			TK&RR	10/1984		739,300	697	717
DEBARY	P1-6	VOLUSIA CO.	GT	F02				04/1976		401,400	282	330
		SECT. 16, 19-21 28-30, T18S, R30E										
HIGGINS	1	PINELLAS CO.	ST	F06		NG	WA	06/1951	12/1999	46,000	229	249
	2	SECT. 35, 36	ST	F06		NG	WA	06/1953	12/1999	46,000	39	40
	3	T25S, R16E	ST	F06			WA	01/1954	12/1999	46,000	41	42
	P1-2		GT	F02			WA	04/1969	12/1999	67,600	39	41
	P3-4		GT	F02			WA	12/1970	12/1999	85,800	50	60
INTERCESSION CITY	P1-6	OSCEOLA CO.	GT	F02				05/1974		340,200	276	342
		SECT. 31 T25S, R28E										
SUWANNEE RIVER	1	SUWANNEE CO.	ST	F06		NG	TK	11/1953		34,500	304	342
	2	SECT. 26, T1S, R11E	ST	F06		NG	TK	11/1954		37,500	33	34
	3		ST	F06		NG	TK	10/1956		75,000	32	33
TURNER	P1-3		GT	F02				11/1980		183,600	159	195
TURNER	3	VOLUSIA CO.	ST	F06		NG	TK&WA	11/1955		78,800	299	339
	4	SECT. 1, T19S, R30E	ST	F06		NG	TK&WA	05/1959		81,600	70	72
	P1-2		GT	F02			TK&WA	10/1970		38,600	71	73
	P3-4		GT	F02			TK&WA	08/1974		142,400	28	34

* REPRESENTS FLORIDA POWER CORPORATION'S SHARE OF U

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* REPRESENTS FLORIDA POWER CORPORATION'S SHARE OF UNIT

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 6.3

PLANNED AND PROPOSED GENERATING FACILITY INSTALLATIONS, CHANGES AND REMOVALS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
PLANT NAME	UNIT NO.	LOC.	FUEL		FUEL TRANSPORTATION		COMMERCIAL IN-SERVICE (MO/YR)	GENERATOR	MAXIMUM NAMEPLATE KW	NET CAPABILITY		STATUS	NOTES
			UNIT TYPE	PRIMARY ALTERNATE	PRIMARY ALTERNATE	ALTERNATE				SUMMER	WINTER		
PURCHASE		SOUTHERN	UN	UN		UN		02/1990		400	400		1
PORT ST. JOE	P1	GULF CO.	GT	F02		TK		06/1991	19,300	14	17	S	
RIO PINAR	P1	ORANGE CO.	GT	F02		TK		06/1991	19,300	14	17	S	
DEBARY	P7-10	VOLUSIA CO.	GT	F02		TK		11/1992		304	364	U	3
INTER. CITY	P7-10	OSCEOLA CO.	GT	F02		UN		11/1993		304	364	P	3
UNIV. PROJECT	P1	ALACHUA CO.	GT	NG		PL		11/1993		37	40	P	
PURCHASE		UNKNOWN	UN	UN		UN		01/1994		200	200		2
UPS PURCHASE	1	SOUTHERN	ST	BIT		RR,TK,WA		01/1994		200	200		
UPS PURCHASE	2	SOUTHERN	ST	BIT		RR,TK,WA		01/1995		200	200		
COMBINED CYCLE	1	POLK CO.	CC	NG	F02	PL	UN	11/1998		200	235	P	3
COMBINED CYCLE	2	POLK CO.	CC	NG	F02	PL	UN	11/1999		200	235	P	3
COMBINED CYCLE	3	POLK CO.	CC	NG	F02	PL	UN	11/1999		200	235	P	3
COMBINED CYCLE	4	POLK CO.	CC	NG	F02	PL	UN	11/2000		200	235	P	3
HIGGINS	1-3	PINELLAS CO.	ST	F06	NG	WA	PL	(12/1999)		(119)	(123)	R	4
HIGGINS	P1-2	PINELLAS CO.	GT	F02	NG	WA	PL	(12/1999)		(50)	(60)	R	4
HIGGINS	P3-4	PINELLAS CO.	GT	F02	NG	WA	PL	(12/1999)		(60)	(66)	R	4
AVON PARK	P1-2	HIGHLANDS CO.	GT	F02	NG	TK	PL	(12/2000)		(50)	(60)	R	4

NOTES :

(1) PURCHASE FROM 02/1990 THROUGH 12/1993

(2) PURCHASE FROM 01/1994 THROUGH 12/1994

(3) ALL CAPACITY DESIGNATED AS COMMERCIAL IN NOVEMBER IS TO MEET ANTICIPATED NEED BEGINNING IN JANUARY OF THE FOLLOWING YEAR.

(4) TO BE RETIRED

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 6.4
PAGE 1 OF 2

EXISTING QUALIFYING FACILITIES
(AS OF MAY 1, 1991)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
FACILITY NAME	UNIT NO.	LOCATION	TYPE	FUEL TYPE		COMMERCIAL IN-SERVICE (MO/YR)	STATUS	AMOUNT OF INTERRUPT. (MW)
				PRIM.	ALT.			
OCCIDENTAL CHEMICAL	* 1	HAMILTON	COG/SSG	WH		01/37	NC	12.0
ST. JOE FOREST PRODUCTS	1	GULF	COG	WD		01/37	NC	0.0
BUCKEYE CELLULOSE	1	TAYLOR	SPP	WD		01/54	NC	0.0
CITRUS WORLD	1	POLK	COG/SSG	NG		10/79	NC	0.0
BEN HILL GRIFFIN	1	POLK	COG/SSG	NG	F06	11/81	NC	0.0
USS AGRICHEM	* 1	POLK	COG/SSG	WH		10/82	NC	20.0
PINELLAS COUNTY RES. RECOV.	1	PINELLAS	SPP	SW		04/83	C	0.0
ST. JOE FOREST PRODUCTS	2	GULF	COG	WD		07/83	NC	0.0
OCCIDENTAL CHEMICAL	* 2	HAMILTON	COG/SSG	WH		05/86	NC	30.0
PINELLAS COUNTY RES. RECOV.	2	PINELLAS	SPP	SW		06/86	C	0.0
TIMBER ENERGY	1	LIBERTY	SPP	WD		07/86	C	0.0
CITRUS WORLD	* 4	POLK	COG/SSG	NG	F02	12/87	NC	1.1
BAY COUNTY RES. RECOV.	1	BAY	SPP	SW	WD	04/88	C	0.0
LFC	1	MADISON	SPP	WD	B10	09/89	C	0.0
LFC	2	JEFFERSON	SPP	WD	B10	06/90	C	0.0
LAKE COUNTY RES. RECOV.	1	LAKE	SPP	SW		09/90	C	0.0
PASCO COUNTY RES. RECOV.	1	PASCO	SPP	SW		03/91	C	0.0

* INTERRUPTIBLE QF'S

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 6.4

PAGE 2 OF 2

EXISTING QUALIFYING FACILITIES
(AS OF MAY 1, 1991)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
FACILITY NAME	UNIT NO.	POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW				OF LOAD SERVED BY OF GENERATION (MW)		PLANT AUXILIARY LOAD - MW		MAXIMUM NORMAL GENERATOR OUTPUT (MW)		CHANGE IN OF LOAD WHEN OF GENERATOR IS OFF LINE AT TIME OF PEAK (MW)		MODELED CAPACITY FACTOR (%)	ANNUAL NET ENERGY TO GRID (GWH)
		FIRM		AS AVAILABLE		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER		
		SUMMER	WINTER	SUMMER	WINTER										
OCCIDENTAL CHEMICAL	* 1	0.0	0.0	4.0	4.0	14.0	14.0	0.0	0.0	18.0	18.0	0.0	0.0	22.6	7.9
ST. JOE FOREST PRODUCTS	1	0.0	0.0	0.0	0.0	35.0	35.0	3.0	3.0	38.0	38.0	38.0	38.0	0.0	0.0
BUCKEYE CELLULOSE	1	0.0	0.0	0.0	0.0	35.0	35.0	0.0	0.0	35.0	35.0	35.0	35.0	0.0	0.0
CITRUS WORLD	1	0.0	0.0	0.0	0.0	0.4	0.4	0.0	0.0	0.4	0.4	0.4	0.4	0.0	0.0
BEN HILL GRIFFIN	1	0.0	0.0	0.0	0.0	0.5	0.5	0.0	0.0	0.5	0.5	0.0	0.0	0.0	0.0
USS AGRICHEM	* 1	0.0	0.0	8.0	8.0	24.0	24.0	0.0	0.0	32.0	32.0	0.0	0.0	38.4	26.9
PINELLAS COUNTY RES. RECOV.	1	0.0	0.0	50.0	50.0	0.0	0.0	4.0	4.0	54.0	54.0	0.0	0.0	69.8	305.7
ST. JOE FOREST PRODUCTS	2	0.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	3.0	3.0	0.0	0.0	2.1	0.6
OCCIDENTAL CHEMICAL	* 2	0.0	0.0	8.0	8.0	20.0	20.0	0.0	0.0	28.0	28.0	0.0	0.0	3.0	2.1
PINELLAS COUNTY RES. RECOV.	2	0.0	0.0	25.0	25.0	0.0	0.0	3.0	3.0	28.0	28.0	0.0	0.0	69.8	152.9
TIMBER ENERGY	1	14.0	14.0	0.0	0.0	0.0	0.0	0.8	0.8	14.8	14.8	0.0	0.0	92.8	113.8
CITRUS WORLD	* 4	0.0	0.0	0.0	0.0	4.0	4.0	0.0	0.0	4.0	4.0	0.0	0.0	0.1	0.0
BAY COUNTY RES. RECOV.	1	11.0	11.0	0.0	0.0	0.0	0.0	0.0	0.0	11.0	11.0	0.0	0.0	75.1	72.4
LFC	1	0.0	0.0	8.0	8.0	0.0	0.0	0.8	0.8	8.8	8.8	0.7	0.7	43.6	30.6
LFC	2	0.0	0.0	8.5	8.5	0.0	0.0	0.6	0.6	9.1	9.1	0.2	0.2	28.1	20.9
LAKE COUNTY RES. RECOV.	1	0.0	0.0	10.0	10.0	0.0	0.0	2.0	2.0	12.0	12.0	1.0	1.0	64.2	56.2
PASCO COUNTY RES. RECOV.	1	0.0	0.0	23.0	23.0	0.0	0.0	3.0	3.0	26.0	26.0	3.0	3.0	69.7	140.4

* INTERRUPTIBLE QF'S

NOTE: COLUMN (3) + (5) = COLUMN (11) - (9) - (7)

COLUMN (4) + (6) = COLUMN (12) - (10) - (8)

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 6.5

PAGE 1 OF 2

PLANNED AND PROPOSED QUALIFYING FACILITIES
(AS OF MAY 1, 1991)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
FACILITY NAME	UNIT NO.	LOCATION	TYPE	FUEL TYPE		COMMERCIAL IN-SERVICE (MO/YR)	STATUS	AMOUNT OF INTERRUPT. (MW)
				PRIM.	ALT.			
DADE COUNTY RES. RECOV.	1	DADE	SPP	SW		11/91	C	0.0
SEMINOLE FERTILIZER	1	POLK	COG	WH		10/92	C	0.0
LAKE COGEN	1	LAKE	COG	NG		08/93	C	0.0
PASCO COGEN	1	PASCO	COG	NG		08/93	C	0.0
ROYSTER PHOSPHATE	1	MANATEE	COG	WH		12/93	C	0.0
EL DORADO ENERGY	1	POLK	COG	WG		01/94	C	0.0
ORLANDO COGEN	1	ORANGE	COG	NG		01/94	C	0.0
RIDGE GENERATING	1	POLK	SPP	BIO		01/94	C	0.0
MULBERRY ENERGY	1	POLK	COG	OTH		01/94	C	0.0
PINELLAS COUNTY RES. RECOV.	3	PINELLAS	SPP	SW		01/95	C	0.0
TIMBER ENERGY	2	LIBERTY	SPP	WD		01/95	C	0.0
GENERAL PEAT	1	HIGHLANDS	SPP	PT		12/95	C	0.0
GENERAL PEAT	2	HIGHLANDS	SPP	PT		12/95	C	0.0
GENERAL PEAT	3	HIGHLANDS	SPP	PT		12/95	C	0.0
ECO PEAT	1	HIGHLANDS	SPP	PT		01/96	C	0.0
STANDARD OFFER	1	UNKNOWN				11/97	NC	0.0
FUTURE NEGOTIATED	1	UNKNOWN				11/97	NC	0.0

FLORIDA POWER CORPORATION
PLANNED AND PROPOSED QUALIFYING FACILITIES
(AS OF MAY 1, 1991)

(1) FACILITY NAME	(2) UNIT NO.	(3) (4) POTENTIAL EXPORT TO GRID AT TIME OF PEAK - MW		(5) (6) AS AVAILABLE		(7) (8) OF LOAD SERVED BY OF GENERATION (MW)		(9) (10) PLANT AUXILIARY LOAD - MW		(11) (12) MAXIMUM NORMAL GENERATOR OUTPUT (MW)		(13) (14) CHANGE IN OF LOAD WHEN OF GENERATOR IS OFF LINE AT TIME OF PEAK (MW)	
		FIRM		AS AVAILABLE		OF LOAD SERVED BY OF GENERATION (MW)		PLANT AUXILIARY LOAD - MW		MAXIMUM NORMAL GENERATOR OUTPUT (MW)		CHANGE IN OF LOAD WHEN OF GENERATOR IS OFF LINE AT TIME OF PEAK (MW)	
		SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER
DADE COUNTY RES. RECOV.	1	43.0	43.0	0.0	0.0	0.0	0.0	0.0	0.0	43.0	43.0	0.0	0.0
SEMINOLE FERTILIZER	1	47.0	47.0	0.0	0.0	0.0	0.0	0.0	0.0	47.0	47.0	0.0	0.0
LAKE COGEN	1	102.0	102.0	0.0	0.0	0.0	0.0	0.0	0.0	102.0	102.0	0.0	0.0
PASCO COGEN	1	102.0	102.0	0.0	0.0	0.0	0.0	0.0	0.0	102.0	102.0	0.0	0.0
ROYSTER PHOSPHATE	1	28.0	28.0	0.0	0.0	0.0	0.0	0.0	0.0	28.0	28.0	0.0	0.0
EL DORADO ENERGY	1	103.9	103.9	0.0	0.0	0.0	0.0	0.0	0.0	103.9	103.9	0.0	0.0
ORLANDO COGEN	1	72.0	72.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0	72.0	0.0	0.0
RIDGE GENERATING	1	36.0	36.0	0.0	0.0	0.0	0.0	0.0	0.0	36.0	36.0	0.0	0.0
MULBERRY ENERGY	1	72.0	72.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0	72.0	0.0	0.0
PINELLAS COUNTY RES. RECOV.	3	40.0	40.0	0.0	0.0	0.0	0.0	0.0	0.0	40.0	40.0	0.0	0.0
TIMBER ENERGY	2	6.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0	6.0	0.0	0.0
GENERAL PEAT	1	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0	52.0	0.0	0.0
GENERAL PEAT	2	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0	52.0	0.0	0.0
GENERAL PEAT	3	52.0	52.0	0.0	0.0	0.0	0.0	0.0	0.0	52.0	52.0	0.0	0.0
ECO PEAT	1	36.5	36.5	0.0	0.0	0.0	0.0	0.0	0.0	36.5	36.5	0.0	0.0
STANDARD OFFER	1	80.0	80.0	0.0	0.0	0.0	0.0	0.0	0.0	80.0	80.0	0.0	0.0
FUTURE NEGOTIATED	1	70.0	70.0	0.0	0.0	0.0	0.0	0.0	0.0	70.0	70.0	0.0	0.0

NOTE: COLUMN (3) + (5) = COLUMN (11) - (9) - (7)
COLUMN (4) + (6) = COLUMN (12) - (10) - (8)

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 6.6

SUMMARY OF FIRM ENERGY AND CAPACITY CONTRACTS
WITH QUALIFYING FACILITIES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
QUALIFYING FACILITY	CONTRACT TERM		CONTRACT CAPACITY		CONTRACT ENERGY		BILLING METHOD	REFERENCE UNIT			NOTES
	FROM (MO/YR)	TO (MO/YR)	NET SUMMER (MW)	NET WINTER (MW)	GWH	CAPACITY FACTOR (%)		NAME	ANTICIPATED IN-SERVICE (MO/YR)	NET SUMMER CAPABILITY (MW)	
PINELLAS COUNTY RES. RECOV. 1	01/95	12/24	40.0	40.0	245.3	70.0	NET	STATEWIDE	01/95		
PINELLAS COUNTY RES. RECOV. 2	01/95	12/24	20.0	20.0	122.6	70.0	NET	STATEWIDE	01/95		
TIMBER ENERGY 1	04/92	04/02	12.8	12.8	78.5	70.0	NET	STATEWIDE	01/92		
BAY COUNTY RES. RECOV.	04/88	12/21	11.0	11.0	71.3	74.0	NET	STATEWIDE	01/95		
LFC 1 (MADISON)	01/90	01/25	8.0	8.0	49.1	70.0	NET	STATEWIDE	01/95		
LFC 2 (JEFFERSON)	06/89	01/25	8.5	8.5	52.1	70.0	NET	STATEWIDE	01/95		GULF
LAKE COUNTY RES. RECOV.	01/95	07/14	10.3	10.3	63.2	70.0	NET	STATEWIDE	01/95		
PASCO COUNTY RES. RECOV.	01/95	12/24	23.0	23.0	141.0	70.0	NET	STATEWIDE	01/95		
DADE COUNTY RES. RECOV.	11/91	11/13	43.0	43.0	312.6	83.0	NET	REF. COAL	01/91-95	450	FPL
SEMINOLE FERTILIZER	10/92	12/07	47.0	47.0	350.0	85.0	NET	REF. COAL	01/91-95	450	TECO
LAKE COGEN	08/93	07/13	102.0	102.0	804.2	90.0	NET	REF. COAL	01/91-95	450	
PASCO COGEN	08/93	07/13	102.0	102.0	804.2	90.0	NET	REF. COAL	01/91-95	450	
ROYSTER PHOSPHATE	12/93	11/08	28.0	28.0	208.5	85.0	NET	REF. COAL	01/91-95	450	
EL DORADO ENERGY	01/94	12/13	103.9	103.9	837.4	92.0	NET	REF. COAL	01/91-95	450	FPL
ORLANDO COGEN	01/94	12/23	72.0	72.0	586.6	93.0	NET	REF. COAL	01/91-95	450	TECO
RIDGE GENERATING	01/94	12/23	36.0	36.0	268.1	85.0	NET	REF. COAL	01/91-95	450	
MULBERRY ENERGY	01/94	12/23	72.0	72.0	567.6	90.0	NET	REF. COAL	01/91-95	450	
PINELLAS COUNTY RES. RECOV. 3	01/95	12/24	40.0	40.0	245.3	70.0	NET	STATEWIDE	01/95	450	TECO
TIMBER ENERGY 2	01/95	01/05	6.0	6.0	36.8	70.0	NET	STATEWIDE	01/95		
GENERAL PEAT 1	12/95	11/25	52.0	52.0	364.4	80.0	NET	STATEWIDE	01/95		
GENERAL PEAT 2	12/95	11/25	52.0	52.0	364.4	80.0	NET	STATEWIDE	01/95		
GENERAL PEAT 3	12/95	11/25	52.0	52.0	364.4	80.0	NET	STATEWIDE	01/95		
ECO PEAT	01/96	12/25	36.5	36.5	271.8	85.0	NET	REF. COAL	01/91-95	450	
NOTE : INDICATE IN COLUMN (12) THE WHEELING UTILITY, IF THE POWER IS BEING WHEELED											

NOTE : INDICATE IN COLUMN (12) THE WHEELING UTILITY, IF THE POWER IS BEING WHEELED THROUGH ANOTHER UTILITY.

FLORIDA POWER CORPORATION
HISTORY AND FORECAST OF ENERGY AND CAPACITY PURCHASES
FROM QUALIFYING FACILITIES

(1) YEAR	(2) NET TO GRID SUMMER CAPACITY (MW)	(3) YEAR	(4) NET TO GRID WINTER CAPACITY (MW)	(5) YEAR	(6) (7) (8) NET TO GRID		
					FIRM ENERGY (GWH)	AS-AVAILABLE ENERGY (GWH)	TOTAL ENERGY (GWH)
ACTUAL:		ACTUAL:		ACTUAL:			
1989	83.8	1989 / 90	91.8	1989	1019.0	0.0	1019.0
1990	100.3	1990 / 91	112.3	1990	961.0	0.0	961.0
FORECAST:		FORECAST:		FORECAST:			
1991	135.3	1991 / 92	167.6	1991	879.0	0.0	879.0
1992	167.6	1992 / 93	202.8	1992	1133.0	0.0	1133.0
1993	355.8	1993 / 94	589.7	1993	1808.0	0.0	1808.0
1994	589.7	1994 / 95	624.2	1994	4178.0	0.0	4178.0
1995	624.2	1995 / 96	768.6	1995	4455.0	0.0	4455.0
1996	768.6	1996 / 97	768.6	1996	5375.0	0.0	5375.0
1997	768.6	1997 / 98	918.6	1997	5543.0	0.0	5543.0
1998	918.6	1998 / 99	918.6	1998	6451.0	0.0	6451.0
1999	918.6	1999 / 0	918.6	1999	6451.0	0.0	6451.0
2000	918.6	2000 / 1	918.6	2000	6469.0	0.0	6469.0
2001	918.6	2001 / 2	918.6	2001	6451.0	0.0	6451.0

NOTE : COLUMN (2) IS THE PROBABILITY WEIGHTED SUM OF COLUMNS (3) AND (5) OF FORMS 6.4 AND 6.5, PAGE 2.
COLUMN (4) IS THE PROBABILITY WEIGHTED SUM OF COLUMNS (4) AND (6) OF FORMS 6.4 AND 6.5, PAGE 2.
COLUMNS (6) AND (7) SHOULD BE THE ENERGY WHICH UTILITIES EXPECT TO PURCHASE FROM THE
QF'S AS REPORTED ON FORMS 6.4 AND 6.5.

FLORIDA POWER CORPORATION

SUMMARY OF SCHEDULED INTERCHANGE CONTRACTS

(1)	(2)	(3)	(4)	(5)	(6)	(7)
PURCHASING UTILITY	SELLING UTILITY	CONTRACT TERM		NET CAPABILITY - MW		DESCRIPTION
		FROM MO/YR	TO MO/YR	SUMMER	WINTER	
FLORIDA POWER	SOUTHERN	2/90	12/92	250	250	SCHEDULE "E"
FLORIDA POWER	SOUTHERN	2/90	12/92	150	150	SCHEDULE "F"
FLORIDA POWER	SOUTHERN	1/93	12/93	400	400	SCHEDULE "E"
FLORIDA POWER	SOUTHERN	1/94	12/94	200	200	SCHEDULE "E"
FLORIDA POWER	SOUTHERN	1/94	5/2010	200	200	UPS #1
FLORIDA POWER	SOUTHERN	1/95	5/2010	200	200	UPS #2

FLORIDA POWER CORPORATION

HISTORY AND FORECAST OF SCHEDULED INTERCHANGE
WITH SOUTHERN COMPANY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
YEAR	SUMMER CAPACITY - MW		YEAR	WINTER CAPACITY - MW		YEAR	TOTAL ENERGY - GWH	
	FIRM	NON-FIRM		FIRM	NON-FIRM		FIRM	NON-FIRM
ACTUAL:			ACTUAL:			ACTUAL:		
1989	0	0	1988 / 89	0	0	1989	0	0
1990	0	400	1989 / 90	0	400	1990	0	2001
FORECASTED:			FORECASTED:			FORECASTED:		
1991	0	400	1990 / 91	0	400	1991	0	1817
1992	0	400	1991 / 92	0	400	1992	0	1926
1993	0	400	1992 / 93	0	400	1993	0	2595
1994	200	200	1993 / 94	200	200	1994	1185	1285
1995	400	0	1994 / 95	400	0	1995	2634	0
1996	400	0	1995 / 96	400	0	1996	2756	0
1997	400	0	1996 / 97	400	0	1997	2727	0
1998	400	0	1997 / 98	400	0	1998	2757	0
1999	400	0	1998 / 99	400	0	1999	2874	0
2000	400	0	1999 / 0	400	0	2000	2903	0
2001	400	0	2000 / 1	400	0	2001	2994	0

FLORIDA POWER CORPORATION
BASE CASE

HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - GWH

		---ACTUAL---												
		1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
INTERCHNG	GWH	1349	1845	1879	2161	3588	3463	3666	3790	3769	3800	3917	3949	4037
NUCLEAR	GWH	2637	3729	4939	4748	5036	4810	5035	4899	5035	4884	5035	4899	5035
COAL	GWH	14722	14822	14991	15212	15342	15328	15351	15101	15723	15824	15569	16047	15672
HO - TOT	GWH	7177	5749	5687	6687	5688	5254	5894	6472	6753	6816	6754	5829	6146
STEAM	GWH	7177	5749	5687	6687	5688	5254	5894	6472	6753	6816	6754	5829	6146
CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
GT	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
LO - TOT	GWH	492	391	278	531	553	364	626	734	851	955	944	772	775
STEAM	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
CC	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
GT	GWH	492	391	278	531	553	364	626	734	851	955	944	772	775
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
NG - TOT	GWH	450	308	0	0	22	196	216	225	219	419	1715	3647	4697
STEAM	GWH	450	307	0	0	0	0	0	0	0	0	0	0	0
CC	GWH	0	0	0	0	0	0	0	0	0	196	1561	3491	4510
GT	GWH	0	1	0	0	22	196	216	225	219	223	154	155	187
DIESEL	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
HYDRO	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
COG & SPP	GWH	1019	961	879	1133	1808	4178	4455	5375	5543	6451	6451	6469	6451
OTHER	GWH	0	0	0	0	0	0	0	0	0	0	0	0	0
NEL	GWH	27847	27805	28652	30472	32037	33592	35243	36597	37893	39149	40386	41611	42814

HISTORY AND FORECAST: INTERCHANGE AND GENERATION BY FUEL TYPE - % OF GWH

[illegible]

FLORIDA POWER CORPORATION
BASE CASE

INDIVIDUAL UTILITY FORM 7.3

HISTORY AND FORECAST: FUEL REQUIREMENTS

		---ACTUAL---		1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
		1989	1990											
NUCLEAR	10E12 BTU	28	39	52	50	53	50	53	51	53	51	53	51	53
COAL	10E3 TON	5756	5757	5610	5710	5760	5744	5716	5628	5855	5891	5794	5909	5769
HO - TOT	10E3 BBL	11731	9390	9267	10810	9302	8590	9620	10533	11001	11081	10961	9333	9831
STEAM	10E3 BBL	11731	9390	9267	10810	9302	8590	9620	10533	11001	11081	10961	9333	9831
CC	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
GT	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
DIESEL	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
LO - TOT	10E3 BBL	1419	1159	633	1199	1192	772	1329	1557	1806	2024	2007	1640	1647
STEAM	10E3 BBL	238	192	0	0	0	0	0	0	0	0	0	0	0
CC	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
GT	10E3 BBL	1181	967	633	1199	1192	772	1329	1557	1806	2024	2007	1640	1647
DIESEL	10E3 BBL	0	0	0	0	0	0	0	0	0	0	0	0	0
NG - TOT	10E6 CF	5495	3742	0	0	205	1817	2009	2090	2034	3751	14576	30823	39541
STEAM	10E6 CF	5495	3727	0	0	0	0	0	0	0	0	0	0	0
CC	10E6 CF	0	0	0	0	0	0	0	0	0	1682	13148	29385	37804
GT	10E6 CF	0	15	0	0	205	1817	2009	2090	2034	2068	1428	1438	1737
DIESEL	10E6 CF	0	0	0	0	0	0	0	0	0	0	0	0	0
OTHER	10E9 BTU	0	0	0	0	0	0	0	0	0	0	0	0	0
ANNUAL AVG NET														
FOSSIL HR	BTU/KWH	9583	9476	9706	9732	9735	9697	9725	9747	9760	9751	9674	9508	9466

FLORIDA POWER CORPORATION

INDIVIDUAL UTILITY FORM 9.3

CERTIFIED AND PROPOSED BULK POWER LINES
(1991-2000)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
UTILITY	TERMINALS		LINE LENGTH (MILES)	NOMINAL VOLTAGE - KV		CONSTRUCTION START (MO/YR)	COMMERCIAL IN-SERVICE (MO/YR)	PURPOSE	STATUS
	FROM	TO		OPERATIONAL	DESIGN				
FPC	Avon Park	Fisheating Creek	30.0	230	230	2/93	12/93	Reliability	CNR
FPC	Silver Springs	Silver Springs North	7.0	230	230	8/93	12/93	Reliability	CNR
FPC	Lk. Tarpon	Kathleen	44.0	500	500	5/92	4/94	Reliability	C
FPC	Debary	Sorrento	20.0	230	230	2/94	12/94	Reliability	CR
FPC	Debary	Winter Springs	18.0	230	230	3/95	12/95	Reliability	CR
FPC	Silver Springs	Central Florida	3.0	230	230	10/95	12/95	Reliability	CNR
FPC	Georgia	Midpoint	100.0	500	500	4/94	1/97	Interconnection	CR
FPC	Central Florida	Midpoint	100.0	500	500	4/94	1/97	Interconnection	CR
FPC	Kathleen	Barcola	45.0	500	500	2/95	1/97	Reliability, Deliver Generator Output	CR
FPC	Newberry	Midpoint	40.0	230	230	5/95	1/97	Reliability	CNR
FPC	Newberry	Archer	12.0	230	230	7/96	1/97	Reliability	CNR
FPC	Polk Site	Ft. Meade #2	6.0	230	230	8/97	11/97	Deliver Generator Output	CNR
FPC	Polk Site	Barcola	5.0	230	230	9/97	11/97	Deliver Generator Output	CNR

NOTE : PLEASE USE ONE OF THE FOLLOWING NOTATIONS IN THE STATUS COLUMN :
 C - CERTIFIED
 CR - CERTIFICATION REQUIRED
 CNR - CERTIFICATION NOT REQUIRED

EXHIBIT B

DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJOR

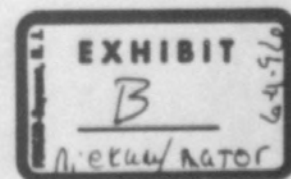
DESCRIPTION: FLORIDA POWER CORPORTION POLK COUNTY
SITE 1994 COST-EFFECTIVENESS ANALYSIS

Florida Power Corporation

Polk County Site

February 18, 1994

-- Draft --



ATTACHMENT LIST

ATTACHMENT I	POLK COUNTY SITE TASK FORCE RECOMMENDATIONS
ATTACHMENT II	ALTERNATE SITE DEVELOPMENT SCENARIOS
ATTACHMENT III	COMPARISON OF RECENTLY CONSTRUCTED POWER PLANT PROJECTS
ATTACHMENT IV	12/30/93 CAPITAL COST ESTIMATES
ATTACHMENT V	O&M COST COMPARISONS
ATTACHMENT VI	PLANNING STUDIES, OPTIONS I, 2, AND 3
ATTACHMENT VII	IMPACTS OF POLK 1 AND 2 DISPLACEMENT BY PURCHASE POWER
ATTACHMENT VIII	PLANNING STUDIES "WHAT IF GAS AVAILABILITY SCENARIOS"
ATTACHMENT IX	WORST CASE REGULATORY COMPLIANCE COSTS
ATTACHMENT X	FINANCIAL ASSESSMENT

FPC POLK COUNTY SITE

CURRENT STATUS

On January 25, 1994, the Governor and Cabinet approved Site Certification for construction of 470 MW of generation at Polk County to be placed in-service 1998/1999. Approval was also granted for ultimate site capacity of 3,000 MW utilizing natural gas, gasified coal and oil as fuel sources. All necessary Federal Permits for construction of the initial 470 MW are expected to be issued by April 1, 1994.

The Florida Public Service Commission (FPSC) granted a Determination of Need for the initial 470 MW on February 25, 1992. Any significant delays in constructing the Polk generation could result in a loss of this need determination and subject FPC to bidding this capacity to others.

FPC can demonstrate that cost estimates for constructing the Polk County generation are well within estimates projected during the need hearings. FPC can also demonstrate that these costs are competitive with other generation options and offer long term strategic and competitive advantages sufficient to overcome perceived future risks.

FPC can demonstrate that no other location on FPC's system is better suited to accommodate the transmission requirements of a base load site.

Polk County is the only generation alternative under consideration which offers fuel flexibility and alternatives to over-reliance on natural gas. Although differential fuel price forecasts do not anticipate benefits to coal gasification, availability of natural gas supply could impact long term operations.

FPC can demonstrate that the Polk County Site will meet all current applicable environmental criteria for power plants and has the approval of all applicable state and federal agencies. However, any future rule changes could be applicable to the Polk County Site.

Certification of the site adds value which allows FPC, FPC and a partner, or a third party to pursue the first and second unit or to pursue supplemental certification of a third, fourth or future units at the site. FPC can be reasonably assured that transmission, cooling pond capacity, water, and power block capacity is available for at least 1250 MW of generation capacity.

Monies already committed on the Polk County project amount to \$30.0 million. FPC may risk non-recovery of these costs if the project is cancelled and no real benefits accrue to its rate payers. No alternatives to Polk have been identified which provide substantive value to FPC rate payers.

Proceeding forward with the Polk County Site is not totally without risk. For future unit additions, FPC will have to comply with new regulatory rules. Certification conditions for the initial units will be reviewed every five years. FPC will have no regulatory entitlements to future unit emissions, discharges, etc. On the other hand, the cost of future megawatts will be very competitive if FPC's decision to invest at Polk County proceeds without major problems.

BACKGROUND

Site Selection

In January 1989, recognizing that forecasts indicated a need for additional generation capacity, FPC began a comprehensive process of locating a suitable site for a large new generation facility. A large site was considered desirable in order to maximize the economies of development and long-term operation.

Specifically, the objective of the site selection program was to determine a primary and alternate site that would be:

- Multi-unit and clean coal capable
- Technology- and fuel-flexible
- Cost effective
- Compatible with FPC's commitment to environmental protection
- In compliance with all government regulations
- Consistent with state and local land use policies

FPC used a systematic site selection approach to ensure that all of the above concerns were fully addressed. The process involved five phases, each with a specific objective.

Phase I

Area Screening, began by screening the entire state of Florida. This phase screened out or eliminated areas that were either environmentally protected or clearly unsuited for development of the proposed facility. Phase I concluded by defining 172 large potential areas suitable for the project.

Phase II

Area Ranking, ranked the 172 potential areas using criteria that evaluated environmental, socioeconomic and engineering issues. Phase II concluded by defining the top 60 candidate areas.

Phase III

Site Identification, identified specific sites among the 60 candidate areas by conducting another screening process on a more refined geographic basis. Phase III concluded by defining 22 potential "semifinalist" sites.

Phase IV

Site Ranking, ranked the 22 semifinalist sites using advanced criteria that further evaluated environmental, socioeconomic and engineering issues. Phase IV concluded by defining the top five candidate sites.

Phase V

The final phase, Site Selection, confirmed the Phase IV site ranking with additional field data and/or analytical evaluation. Phase V concluded in October 1990 by identifying the preferred and alternate sites.

Throughout this lengthy process, FPC was assisted by an independent group of environmentalists, educators, and community leaders. This Environmental Advisory Group provided advice on matters of public concern, with their major function being to review plans for each of the five phases of the siting process and suggest changes in the evaluation process. FPC also systematically elicited the preferences of this independent panel for use in the development of ranking criteria used in the evaluation process. In addition to the input received from the Environmental Advisory Group, FPC consulted with various regulatory agencies at specific points in the process to obtain their perspective on siting criteria.

As a result of this extensive statewide search, FPC selected a location in Polk County as the primary site of its next generating units and an alternative site in Hardee County. The Environmental Advisory Group supported this decision. Both locations met FPC's goal for a large site capable of handling staged development of various generation and fuel options. FPC's research indicated that the Polk County Site was capable of supporting approximately 3,000 MW total generation.

Following the site selection process, further evaluations were conducted assessing the merits of the preferred and alternate sites. Hardee County was ultimately discarded due to more extensive transmission requirements to connect into the FPC grid and the substantial land costs associated with the value of phosphate reserves contained on the available properties.

Generation Technology Selection

FPC's need for additional generation was based upon specific system reliability criteria. A set of 10 generation expansion alternatives were developed which would satisfy FPC's system reliability criteria. These 10 alternatives were evaluated to ensure that FPC examined and quantified the costs and benefits of a variety of generation expansion technologies, plant sizes, and construction options.

In developing the expansion alternatives, FPC considered four major constraints. First, the technologies used in alternative plans must meet FPC's criteria for technical feasibility, reliability, and potential cost effectiveness. Second, the alternative plans must result in a system that meets or exceeds FPC's reliability criteria during each year of the plan. Third, the alternative plan must be consistent with FPC's commitment to environmental protection, and in particular must permit FPC to comply with the revised Clean Air Act limitations on sulfur dioxide emissions. Finally, the alternative must represent a plan that is well integrated with the present operation and configuration of the FPC system.

The 10 generation alternatives that were evaluated included combinations of large and small pulverized coal (PC) units, CTs, CCs, fluidized bed, and coal and oil emulsion (emulsified low grade Venezuelan crude oil) gasification plants, and additional capacity purchases from existing, low cost units. Each of the alternatives would come into service between 1997 and 2000.

FPC's economic evaluation of the 10 alternatives included cumulative present worth revenue requirement comparisons. In addition, FPC evaluated 27 different uncertainties for each alternative based on the high, medium and low demand and energy forecast; the high, medium, and low fuel forecast; and the high, medium, and low conceptual cost estimates. The final result of this decision analysis was an expected cumulative present worth revenue requirement of that alternative on FPC's system. Supporting

data was also generated for 27 various scenarios which, when accumulated with their probability of occurring, would equal their expected value. Cumulative and annual cost curves were also generated over time to enable revenue requirement cash flow comparisons.

The Polk County CC plants emerged from all of these calculations as the most cost-effective alternative. In other words, these units were expected to lead to the lowest cost of service and the lowest rates, when viewed on a present value or present worth basis. The units also did not pose any unusual risks in the event that some of the key planning assumptions used by FPC turn out to vary according to their expected probability distribution.

Need Determination

In August 1991, FPC petitioned the FPSC for a determination of the need to construct four natural gas-fired combined cycle (CC) generating units at Polk County during the years 1998-2000. In that petition, an integrated resource study demonstrated that FPC will require additional generating resources to meet customer load growth in the years following 1997.

FPC's planning studies called for meeting 1,445 megawatts (MW) of demand - almost 30 percent of projected load growth - with demand side management programs. An additional 751 MW - about 15 percent of load growth would be provided by qualifying facilities, all of which already had signed contracts with FPC. FPC would also install about 384 MW of combustion turbine (CT) peaking capacity in November 1992 and 404 MW of CT peaking capacity in November 1993. Additional capacity equivalent to 984 MW would be added with the completion of a 500-kilovolt (kV) tie line to the Southern Company, a purchase from the Southern Company, and the addition of interruptible load customers. The integrated resource study demonstrated that the remainder of FPC's load growth - approximately 940 MW could be supplied in a cost-effective manner by the Polk County units.

The Polk County units, together with the proposed conversion of existing FPC generation at Anclote, would allow FPC to make a substantial commitment to the use of natural gas. This commitment would play a key role in bringing new natural gas transportation capacity to Florida. The use of natural gas also would play a vital role in FPC's compliance strategies for meeting the Clean Air Act requirements for the year 2000.

On February 25, 1992, the PSC determined the need for the first 470 MW of CC power plants, fueled primarily with natural gas. The PSC, which has sole responsibility for the determination of need for the facility, concluded that

[T]he first two proposed combined cycle units on Florida Power Corporation's proposed Polk County Site will contribute to electric system reliability and integrity.... [T]he addition of the first two units will enable Florida Power to meet ... winter reserve margin criteria and to withstand the outage of its largest unit at time of system peak. The combined cycle technology chosen is a sufficiently mature and reliable generating option for Florida Power's system. The first two Polk County units will contribute to diversifying Florida Power's system fuel mix, and thus contribute to the integrity of Florida Power's system.

The PSC also concluded that

[T]he first two proposed Polk County units will contribute to the provision of adequate electricity to Florida Power and the State of Florida at a reasonable cost ...

...

[T]he reasonably anticipated costs of environmental compliance of the first two Polk County units have been adequately considered ...

...

Florida Power selected the Polk County Site ... with the assistance of a group of educators, environmentalists, and community leaders The site preparation will be predominantly the same for two units as it would be for four units.... [I]t is important for Florida Power to secure a site to meet its future generation needs, and approval of the first two Polk County units will be sufficient to that end.

...

Florida Power has demonstrated that it reasonably considered capacity purchases from other utilities and non-utility generators to meet future generation needs.

...

Florida Power has adequately considered the conservation measures that are reasonably available to it to avoid the need for capacity as required by section 403.519, F.S.

Polk County Approval

Following a 8-month local review process and a public hearing, Polk County issued a conditional use permit approving the project. The Polk County Board of County Commissioners approved the conditional use permit for the Polk County Site on June 2, 1992. This approval was a prerequisite to the Power Plant Siting Act land use hearing, the purpose of which is to determine whether the site is consistent and in compliance with existing land use plans and zoning ordinances. The land use hearing was held December 7, 1992, and the Governor and Cabinet subsequently held that the project is consistent and in compliance with the land use plans and zoning ordinances of Polk County and Hillsborough County.

Site Certification

Upon the filing of its licensing application in August 1992, FPC initiated a review of the project by various state, regional and local agencies and interested parties. The Florida Department of Environmental Protection is the agency designated under the law to coordinate the review process.

The stages of the certification process and the achievement of various milestones were as follow:

Application Filing - August 24, 1992
Completeness Review - September 9, 1992
Sufficiency Review - April 8, 1993
Land Use Hearing - December 7, 1992*
Certification Hearing - October 26, 1993 and November 2, 1993
Recommended Order - December 3, 1993
Certification - January 25, 1994

- * 1/26/93 - Governor and Cabinet issued a final order finding the Polk County Site is consistent with all applicable zoning ordinances and land use plans.

In this case, certification constitutes approval to construct and operate 470 megawatts of natural gas-fired combined cycle generating capacity and a determination that the Polk County Site currently has the environmental resources necessary to support an ultimate capacity of approximately 3,000 megawatts of combined cycle generating capacity fueled by a combination of natural gas (1,000 MW) and coal-derived gas (2,000 MW), as primary fuels, and distillate fuel oil as the back-up fuel.

Based on the ultimate site capacity determination, FPC will be able to seek approval of additional power plant units (beyond the initial 470 megawatts) at the Polk County Site through a supplemental application process. In this process, application requirements are reduced and the timetable for review is shortened. Approximately 1 - 1½ years can be reduced from an expected 3 year certification effort.

Federal Permits

Environmental Protection Agency

On December 15, 1993, the Environmental Protection Agency (EPA) informed FPC in writing that the Polk County Site cooling pond is considered "a wastewater treatment system" and will not need a National Pollution Discharge Elimination System (NPDES) permit. Consequently, no further EPA permit is required for the zero discharge cooling pond. This issue had been argued with EPA for almost two years to avoid EPA jurisdiction of proposed cooling ponds as "Waters of the U.S."

Army Corps of Engineers Permit

On November 17, 1993, FPC submitted an Army Corps of Engineers (ACOE) permit application for construction at the Polk County Site. The application requests a 30-year permit for dredging and filling activities in the on-site mine cuts. The ACOE alleges that it has jurisdiction over the 951 acres of waterbodies and 289 acres of wetlands in the mine cuts. In filing the application, FPC did not concede that the ACOE has jurisdiction, but stated that it was attempting to avoid further disputes.

The ACOE issued a public notice for the application on December 14, 1993, requesting any comments within 30 days of the notice. The U.S. Fish and Wildlife Service has verbally advised that it has no objection to the issuance of the permit. The Florida Department of Environmental Protection has addressed and resolved its concerns through the site certification process. The EPA was present during the ACOE's field visit when the wetlands delineation was performed, and could potentially comment on the application. However, the environmental enhancement program should satisfy any wetlands concerns.

Issuance of the ACOE permit should occur by mid-March, 1994.

Prevention of Significant Deterioration Permit

With the return of delegated authority to the state, the DEP will actually issue the Prevention of Significant Deterioration (PSD) permit. Issuance of the PSD permit is expected by mid-March, 1994.

Costs

Polk County project expenditures booked to date (through 12/93) total approximately \$26.9 million including AFUDC. A breakdown of these costs includes:

Site Selection	1,669
Site Certification, Licensing, and Preliminary Engineering	
FPC Salaries and Expenses	2,687
Outside Legal	1,190
Black & Veatch	741
Ebasco	12,814
Other Outside Services	52
Land, Reclamation and Sitework	
Land Options	1,034
IMC Clay Pipeline Relocation	3,900
GAC	<u>38</u>
Total Cost Less AFUDC	24,123
AFUDC	<u>2,798</u>
Total	26,921

Expenditures incurred/committed but not yet booked are estimated to be \$2.8 million.

Obligations

In the event FPC were to decide to cancel the Polk County project, there is one contractual obligation with the City of Bartow which would need to be negotiated. By Agreement, FPC is obligated to accept treated sewage effluent from the City for a twenty year period commencing in 1998. Since the original agreement had an escape clause of September 1993 (based on Governor and Cabinet approval in October 1993), it is anticipated that FPC could negotiate relief from this obligation. Other exit costs are deemed to be "incidental". Discussions with FPC financial sources indicate that FPC could negotiate the amortization of "sunk costs" with regulators if this project were cancelled. To be successful, FPC would need to demonstrate that rate payers benefited through a decision to cancel and that the decision was made at an appropriate time in the life of the project.

POLK COUNTY COMPETITIVE POSTURE

Since the site selection for FPC's large new generation facility began in January 1989, significant change has happened in the electric utility industry. Competition, pending deregulation, technology and environmental initiatives are among the primary drivers of this change.

In order to position itself to compete more effectively in the future, FPC has implemented significant changes within the past twelve months including organization changes, downsizing and challenges to traditional approaches to doing business. Questions concerning the competitive advantage of the Polk County Site have been one of many key concerns in this evolutionary process.

Task Force Initiatives

In April 1993, a task force representing a cross section of corporate functions was convened to address the issue of Polk County's competitive posture. The "issue" was verbalized as follows:

"Given the changed competitive climate and our plan to continue aggressively competing for future generation, is the Polk County Site the location where we can build the lowest cost generation? If so, we should continue efforts to license the site, if not, we should look for a site that will allow us to be the low cost producer.

If the decision to proceed is based on the competitiveness of the site following initial unit development, what is the risk that we will be prevented from constructing future units at the site, thus making the site non-competitive?"

A list of "pros" and "cons" was developed to support a task force recommendation on whether to proceed with the Polk County Site. The recommendations included:

- Management make an affirmative decision to stay in the new generation business.
- Complete the licensing process. If major issues that are not resolvable come up at the hearing, then revisit the issue.
- Revise ultimate generation mix to blanket a scenario of 1,000 MW natural gas and 2,000 MW coal gas.
- Prudently phase site development to minimize upfront expenditures.
- Explore early acquisition of 500kV corridor between Polk units and Kathleen to provide additional site transmission capability.
- Participate in rulemaking of Environmental Cost Recovery Clause to realize recovery of licensing costs as appropriate.

A copy of the final report issued by the task force is included as Attachment I to this report.

Polk County Site Advantages

Establishment of the Polk Site provides for the capability of additional competitive incremental expansion at a location on our system where it is needed and which does not present serious additional environmental concerns.

Specific advantages of the site include:

- FPC may lose the Polk County need determination if it is does not go forward in a timely manner. There is a value to the need determination previously granted by the FPSC.
- Site certification is assured; cancelling project now would impact credibility with regulators and public unless rate payers experienced real value from alternative plan.
- 1900 MW transmission capability is reasonably certain at the site due to existing facilities and the ability to connect into FPC's 230kV grid. No other single location on the FPC system is better suited for such large additional generation capability.
- Polk units are important to the gas pipeline profitability in the 1998 and beyond timeframe. The Company also has a significant need and use for the fiber optic component of the pipeline.

- \$30 million has already been invested on licensing, land options and preliminary site development. To stop now would mean a possible \$30 million O&M expense.
- The site has support from the PSC, local governments, environmental groups, and the local public.
- The certification of the Polk County Site preserves the option for FPC to build the first two units or future units and has value. Certification of the site allows FPC, FPC and a partner, or a third party to pursue supplemental certification of a third, fourth, or future power plant at the site. Supplemental certification is not guaranteed and may require a longer lead time than small unit construction at multiple scattered sites.
- FPC needs to preserve and increase fuel flexibility in the system.
- A potential exists to employ compressed air storage technology for future unit additions at Polk County. A current R&D project is exploring feasibility. Employing this technology would reshape FPC's load curve, improve system capacity factor and result in more competitive generation costs.

Polk County Site Concerns

The environmental concerns are manageable, and are not the driving factor. The developmental costs of the site may be so great as to adversely affect the cost of generation. Specific concerns regarding the site include:

- Now may not be the time to pay upfront for a coal capable site.
- Will the PSC allow all of the costs to be recovered in rate base? Even if this is allowed, will the PSC disallow recovery of unused "higher cost units" as competition increases? (This assumes a regional wide surplus.)
- The PSC will certainly be changing. Will FPC get the same support in six years that it has now?
- The cost of the early units may not be competitive with EWG's because of the total build-out costs absorbed upfront.
- If fuel cells and distributed generation become a competitive reality, will the Polk County Site remain competitive into the next century?

Capital Cost Competitiveness

Since the original Site Certification Application was filed with the FDEP on August 24, 1992, significant changes to site development scope have been discussed internally and negotiated with involved agencies. Some of these changes were agency driven to conserve resources (water) while others were FPC driven to minimize upfront as well as ultimate site development expenditures. Attachment II defines nineteen site development scenarios which were prepared in the third quarter of 1993 to assess site development options and related cost impacts. Following a series of presentations to senior management, a preferred option was chosen which eliminated the pulverized coal option for ultimate site build-out. This option restricted ultimate site capacity to no more than 2,000 MW on coal gas and 1,000 MW on natural gas. The initial 1,000 MW will be on natural gas.

The selected option is designated "3E" on Attachment II and was chosen for its reasonably competitive cost for the initial 470 MW of site generation (\$803/kW) and its very attractive cost of \$448/kW for future unit additions. This option compared favorably against the cost of recent generation additions throughout Florida (Attachment III) and was carried forward in final certification negotiations with state agencies.

Most recent cost updates (12/30/93) forecast the initial units to cost \$633/kW, a \$30/kW increase from third quarter forecasts. These cost updates incorporate overhead and consulting fees which had not been accounted for in previous estimates. Attachment IV shows the most recent capital cost forecast. Estimates are in current day dollars without AFUDC. Latest estimates still compare favorably against recent competitive additions and are \$73/kW less than those presented during FPC's Need Determination before the FPSC in November 1991.

O&M Cost Competitiveness

Within the past several months, efforts have been ongoing to assess the O&M competitiveness of the Polk County units against competing new generation. Agency imposed "Conditions of Certification" were of particular concern regarding their cost impacts on overall generation costs. Attachment V is a cost matrix including all known O&M costs, including fuel, for the Polk County units and several "competitor" units.

Two alternatives were developed for "competitor" units. One assumed comparably configured units to what FPC is intending to build at Polk County but on a "postage stamp" site utilizing cooling towers for plant cooling water needs. This competitor configuration would need to undergo certification and comply with associated certification conditions. The second alternative assumed a competitor unit size which would just escape the power plant certification threshold. It would require permits similar to those associated with FPC peaking additions. It too would be on a "postage stamp" site and utilize cooling towers for heat transfer.

Attachment V demonstrates that O&M, including fuel, costs for the initial 470 MW at Polk County are approximately 1.2% lower than the nearest competitor unit. This assumes natural gas transportation costs at SunShine pricing for FPC and FGT pricing for FPC's competitors. If gas transportation is considered equal (FGT pricing for both FPC and its competitors), Polk County O&M costs are approximately .6% higher than its nearest competitor. Addition of future units at Polk County enhances FPC's competitive position.

The bottom line result demonstrates that the Polk County initial generation is competitive on O&M cost.

Options for Future Generation Expansion

Three options for the development of future generation were analyzed. The assumptions and a description of each option is as follows:

Assumptions:

DSM goals planning optimized base case.
 Updated capacity, heat rate and cost data for Higgins and Turner full repowering.
 Medium Fuel and Demand and Energy Forecast.
 Siemens CT in-service January, 1996.
 SunShine Pipeline available to Anclote in 1996.
 The incurred/committed cost of the Polk Site is \$64/kW for Units 1 & 2.

Option 1:

Polk Units 1 and 2 are built as planned with November 1998 and 1999 in-service. Capital cost for these units is \$569/kW (1993 \$), the cost of Polk units 3 and 4 are \$487/kW.

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Polk Unit 1 Combined Cycle	235
2000	Polk Unit 2 Combined Cycle	235
2001	Higgins Steam Repowering	248
2002	Turner Steam Repowering	488
2003	No additions	
2004	Higgins Steam Repowering	124
2004	Polk Unit 3 Combined Cycle	235
2005	Polk Unit 4 Combined Cycle	235

Option 2:

Option 2 is the same as Option 1 with the exception of the site size. A small Polk Site is selected changing the cost of Polk Units 1 and 2 to \$528/kW. However, the cost of two future combined cycle units at an undetermined postage stamp site becomes \$558/kW.

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Polk Unit 1 Combined Cycle	235
2000	Polk Unit 2 Combined Cycle	235
2001	Higgins Steam Repowering	249
2002	Turner Steam Repowering	498
2003	No additions	
2004	Higgins Steam Repowering	124
2004	Combined Cycle (postage stamp)	235
2005	Combined Cycle (postage stamp)	235

Option 3:

The Turner and Higgins repowering projects are moved to 1998 and 1999. Future combined cycle units are assumed to be built at smaller sites, their capital cost is now \$558/kW (1993 \$).

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Higgins Steam Repowering	249
2000	Turner Steam Repowering	498
2001	Unit 1 Combined Cycle	235
2002	Unit 2 Combined Cycle	235
2003	No Additions	
2004	Higgins Steam Repowering	124
2004	Unit 3 Combined Cycle	235
2005	Unit 4 Combined Cycle	235

Comparison:

The difference in the cumulative present worth revenue requirements for (CPWRR) Options 1, 2 and 3 is shown in Attachment VI. By 2004, Option 2 has a CPWRR that is \$11,671,000 lower than Option 1 and Option 3 is \$3,315,000 lower than Option 1. However, by 2010, Option 2 is \$1,025,000 higher than Option 1 and Option 3 is \$13,715,000 higher than Option 1. Options 2 and 3 continue to have higher CPWRR's over the life of the study (2032).

Option 1 is the lower cost option to construct four gas fired combined cycle units. This advantage is obtained due to the lower incremental costs involved in constructing Units 3 and 4 at the Polk County Site. There are continued savings if the Polk County Site is expanded further.

Options 2 and 3 are the lower cost options if no additional units beyond Polk 1 and 2 are assumed.

Possible Purchased Power Payments

A schedule is attached (Attachment VII) of payments that FPC would be required to pay a QF or IPP to construct and maintain the equivalent capacity of the proposed postage stamp combined cycle units in Option 3. The first sheet estimates payments required for the initial 470 MW of combined cycle units. The second sheet estimates payments required for the final 470 MW block of combined cycle units. The third sheet represents total payments required for the four combined cycle postage stamp units, or 940 MW, of Option 3.

WHAT IF SCENARIOS

What if the pipeline is delayed?

Currently the SunShine Pipeline is planned for an in-service date of 12/95. This is almost three years prior to the first Polk County Unit. Therefore, any delay up to mid 1998 is of no consequence to Polk County, assuming the project is completed on time.

If the pipeline is delayed beyond the start-up of Polk County, the magnitude of the impact would depend on the duration of the delay.

Short term: If the delay were a matter of months (permitting or construction problems) short term measures could be taken. Operation on low sulfur light oil is an option, although expected permits limit the hours of operation to 500/yr. This would result in higher cost, lots of truck traffic at the site, higher emissions and more maintenance. Reliability also would go down due to the limited site storage planned for oil since it is currently planned to be a back-up fuel only. Cost impacts of operating on #2 oil rather than gas are about \$28 million for a one year delay (Attachment VIII, part I). If the gas conversion at Anclote could be delayed until 1998 and 1999 to match up with the pipeline delay, a potential overall savings of \$213,000 can be demonstrated.

Long term: If the delay is a matter of a year or more, other measures could be explored utilizing the backup pipeline corridor developed in the site certification. A lateral and meter station could be connected to the Florida Gas Transmission (FGT) system to provide interruptible or released (temporary) Firm Capacity to the site. This gas supply would be far less reliable than SunShine Firm Capacity and low sulfur light oil would be used frequently during peak natural gas demand periods. Alternatives to provide a longer term fuel supply until SunShine were available could include:

- Modifying permit conditions to allow for increased operating hours on light oil.
- Increasing fuel oil tankage or building some of the future tanks early to enhance oil supply reliability.
- Installing LNG storage facilities to store natural gas available off-peak to utilize on-peak.
- Installation of propane facilities.
- Longer term commitment to FGT Transportation.

Delays past 2000 would also cause Clean Air Act compliance problems. Short term measures such as switching other plants to very low sulfur oil and/or buying emission credits could be implemented.

What if the pipeline is cancelled?

Cancellation - If the SunShine Pipeline is cancelled, FPC would have to arrange for alternative transportation for natural gas supply to Polk County and Anclote. If the cancellation is known early enough, FPC could reevaluate multiple options, such as:

- Contracting with Florida Gas Transmission.
- Developing alternatives with Peninsula Pipeline (SONAT), Koch or others.
- Constructing a pipeline ourselves.

If sufficient lead time is not available to develop other alternatives, then the Florida Gas Transmission alternative is the only viable option. Assuming Phase III is completed as planned, Phase IV or V expansion to serve Polk County could be developed with a 3 year lead time.

An estimate of the cost impact of FGT gas supply compared to SunShine could range from a savings of \$35 million (NPV) to a cost of \$33 million (NPV) depending on the assumptions used (Attachment VIII, part II).

What if gas prices become uncompetitive?

Natural gas prices incurred by FPC for Polk County could be uncompetitive at several different levels:

- With other power generators' natural gas cost.
- With other power generators based on residual fuel oil or coal burned in boilers.
- With other technology options such as coal gasification.

Each of these are addressed below:

Others' natural gas cost: Unless FPC makes a significant error in its procurement of gas supply or transportation, significant differences between FPC's cost of gas and its competitors is unlikely. Those customers of FGT who have significant capacity on the existing system through Phase II will have some cost advantages in pipeline rates once they have paid off all of FGT take-or-pay liabilities. FGT's Phase II rates compare with Phase III expected rates and SunShine as follows:

FGT Phase II (w/o take or pay charge)	\$/MMBTU*
FGT Phase III	.392
SunShine/SITCO (w/o upstream cost)	.786
	.673

* Doesn't include GRI or ACA Surcharges or Compressor Fuel Allowance.

Other Fuels: Natural gas is one of the highest cost fuels for generating electricity on a \$/MMBTU basis. Of course the low capital cost for the power plant, its high efficiency and low emissions more than offset the fuel price penalty. If the price differences between the fuels are great enough, less efficient coal and residual fuel oil steam plants could dispatch ahead of Polk County. The impact would be a lower load factor at Polk County.

Coal Gasification: Long term coal gasification or other technologies could become more cost effective than natural gas fired combined cycles. The Polk County site is capable of hosting coal gasification plants. However, the current site certification conditions would require supplemental certification to allow this for the first 1,000 MW at the site.

Based on the expected range of fuel prices and capital costs for facilities, the likelihood of coal gasification becoming cost effective for FPC in the next ten to twenty years is very low. The 25 year gas transportation commitment with SunShine plus any future upstream pipeline and supply commitments would also have to be dealt with if Polk's fuel source were to be changed.

What if SWFWMD or Polk County declare a water shortage and groundwater becomes unavailable?

In the event groundwater became unavailable at the Polk County Site, construction and operations would not be impacted for up to 1250 MW of unit installations. FPC has an agreement in place with the City of Bartow for use of up to 5.0 million gallons per day (MGD) of reclaimed water. Use of water cropping provides an additional 5 MGD. These quantities are sufficient to support approximately 1250 MW fired on natural gas.

Additionally, the local region produces approximately 40 MGD of reclaimed water some of which potentially could be accessed by FPC. With its water storage capability, the FPC site lends itself well to accommodating high volumes of reclaimed water use. Discussions are ongoing with the City of Lakeland to gain "Rights of First Refusal" on future reclaimed water needs. FPC is also participating in a study with regional agencies considering feasibility of a regional reclaimed water pipeline.

In the event of a "worst case" scenario (assuming no groundwater or additional reclaimed water availability), build-out beyond 1250 MW would require dry cooling technology for base load units or additions limited to peaking capacity. Dry cooling would increase the installed cost of base load generation additions by approximately 10%.

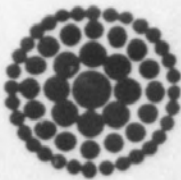
What if worst case regulatory compliance costs are assumed at Polk County?

Attachment IX, prepared by Environmental Services, depicts worst case regulatory compliance costs for "Conditions of Certification" granted Polk County. The significant cost impacts involve air compliance (page 1) and wetlands reclamation (page 11). Competitive facilities are at similar risk under air compliance as the Polk County units. They are typically not at risk for wetland reclamation.

ATTACHMENT I

POLK COUNTY SITE

TASK FORCE RECOMMENDATIONS



Florida
Power
CORPORATION

INTEROFFICE CORRESPONDENCE

Environmental Services Department

H2G

231-5529

SUBJECT: Polk County Site
Task Force Recommendation

FROM: Kathleen L. Small *KLS*

TO: Distribution

DATE: May 24, 1993

Attached is the recommendation concerning the Polk County Site which was presented to Mr. J. Hancock on May 21, 1993. Also attached is a cost comparison of various site development scenarios.

Attachments

cc: E. G. Major

pag\CLSU1993\Polk2.Memo

Distribution:

P. Blizzard
R. Blush
G. Campbell
M. Foley
S. Purvis
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File: ESD&C 4.14.0800
ESD 3000 MW B-1

POLK COUNTY SITE

ISSUE: Given the changed competitive climate and our plan to continue aggressively competing for future generation, is the Polk County site the location where we can build the lowest cost generation? If so, we should continue efforts to license the site, if not we should look for a site that will allow us to be the low cost producer.

If the decision to proceed is based on the competitiveness of the site following initial unit development, what is the risk that we will be prevented from constructing future units at the site, thus making the site non-competitive?

PROS:

1. We will lose the Polk County need determination if we do not go forward. There may be a value to the need determination.
2. 1900 MW transmission capability is reasonably certain at the site due to existing facilities and the ability to connect into our 230kV grid. No other single location on the FPC system is better suited for such large additional generation capability.
3. Polk units are important to the gas pipeline profitability in the 1998 and beyond timeframe. The Company also has a significant need and use for the fiber optic component of the pipeline.
4. \$25 million has already been invested on licensing, land options and preliminary site development. To complete the licensing will not require a substantial additional investment. To stop now would mean a possible \$25m O&M expense.
5. The site has support from the PSC, local governments, environmental groups, and the local public.
6. There is a possibility of immediately recovering some of the licensing costs related to wetland protection and water quality through the new Environmental Cost Recovery factor.
7. The Certification of the Polk County Site preserves the option for FPC to build the first two units or future units and has value. Certification of the site allows FPC, FPC and a partner, or a third party to pursue supplemental certification of a third, fourth, or future power plant at the site.
8. The PSD increment for the Polk County Site has value.
9. We need to preserve and increase fuel flexibility in the system.

PRO SUMMARY: Establishment of the Polk Site provides for the capability of additional competitive incremental expansion at a location on our system where it is needed and which does not present serious additional environmental concerns.

CONS:

1. Now is not the time to pay upfront for a coal capable site.
2. Environmental concerns - consumptive water use, COE jurisdiction over waters of the U.S., EPA jurisdiction over cooling ponds - may delay licensing.
3. Will the PSC allow all of the costs to be recovered in rate base? Even if this is allowed, will the PSC disallow recovery of unused "higher cost units" as competition increases? (This assumes a regional wide surplus.)
4. The PSC will certainly be changing. Will FPC get the same support in 6 years that it has now?
5. The cost of the early units may not be competitive with EWG's because of the total buildout costs absorbed upfront.
6. If fuel cells become a competitive reality, will the Polk County site remain competitive into the next century?

CON SUMMARY: The environmental concerns are manageable, and are not the driving factor in this argument. The developmental costs of the site may be so great as to adversely affect the cost of generation.

RECOMMENDATIONS:

1. Management make an affirmative decision to stay in the new generation business.
 - 1a. Complete the licensing process. If major issues that are not resolvable come up at the hearing, then revisit the issue.
2. Revise ultimate generation mix to blanket a scenario of 1000 MW natural gas and 2000 MW coal gas.
3. Prudently phase site development to minimize upfront expenditures.
4. Explore early acquisition of 500kV corridor between Polk units and Kathleen to provide additional site transmission capability.
5. Participate in rulemaking of Environmental Cost Recovery Clause to realize recovery of licensing costs as appropriate.

**FLORIDA POWER CORPORATION - POLK COUNTY SITE
PRELIMINARY COST COMPARISON
MAY 19, 1993**

	ORIGINAL ESTIMATE (4/92)	BASE ALTERNATE (5/93)	ALTERNATE 1-A (5/93)	ALTERNATE 1-B (5/93)	ALTERNATE 2-A (5/93)	ALTERNATE 2-B (5/93)
DESCRIPTION	This plan appears in the SCA. This includes structurally filling the Plant Island Area (SA-11, SA-12 and SA-13 in the first phase of development. Tiger Bay would be modified to provide flows to McCullough Creek. Pulverized Coal is a consideration as a future fuel source.	Modification of the existing SCA plan. Includes eliminating PC fuel source (and thus the Phosphoria SWDA) and realigning the Plant Island Area to accommodate flows from ESTECH through SA-12 to McCullough Creek. The Power Block Area (SA-11) would be dewatered and structurally filled from bedrock.	This is a phased version of the Base Alternate arrangement. This includes phasing the filling of the Plant Island Area such that only SA-11 and SA-13 are structurally filled in the initial phase (1998). The SA-12 area would be filled when coal would be added as a fuel source. Also, the N-16 Cooling Pond would be constructed in two phases that correspond to the Plant Island filling. All other land uses and in-service dates remain the same as the Base Alternate.	This alternate substitutes augered piles in-place of structural fill in Alternate 1-A. All other development considerations are the same (i.e. phasing, etc.).	This alternate proposes cooling towers in place of a cooling pond system. The Plant Island Area would be constructed in the initial phase in the SA-11, SA-12 and SA-13 areas, with a portion of the SA-12 area remaining undisturbed to provide flows to McCullough Creek (as in the Base Alternate). The Power Block Area would be structurally filled from bedrock. A 225-acre portion of the N-16 area would used as a water storage area with the remaining being reclaimed as water crop or buffer. The N-11B area is used as the Phase II SWDA in place of P-2.	This alternate substitutes augered piles in-place of structural fill in Alternate 2-A. All other development considerations are the same (i.e. cooling towers, etc.).
DEVELOPMENT COST (1998)	\$70,400,000	\$64,206,000	\$58,120,000	\$52,065,000	\$58,919,000	\$61,653,000
LATE DEVELOPMENT COST (2017)	\$90,160,000	\$84,941,000	\$92,588,000	\$136,459,000	\$134,437,000	\$255,604,000

Estimates include a 5% per year escalation in unit prices.

Estimates prepared as part of the Alternate Site Arrangement Report prepared May 19, 1993 by Dames & Moore.

ATTACHMENT II

ALTERNATE SITE DEVELOPMENT SCENARIOS

FPC POLK COUNTY SITE TABULATION OF CO² CALC 55 AND 58

SCENCO-3.XLS 7/16/93 7:34 page 2 of 4

Scenario's	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/Ultimate
3A. Case A: 1000 Mw NGCC 2000 Mw CGCC Structural Fill Reclaimed Water/Delete P-3 & Phos.	2043 Estech 5211 IMC 7254 acres \$8,125,623	97,245,623 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 304,230,848	0 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 206,985,225	131,713,623 S.P. 250,000,000 H.D. 1,064,581,350 EQ. 22,368,256 R.W. 1,468,643,229	206.91 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$647.30 (470,000 kw)	0.00 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$440.39 (470,000 kw)	43.90 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W. \$489.55 (3,000,000 kw)	1200 2260
3B. Same as 3 except Phased Piles	2043 Estech 5211 IMC 7254 acres \$8,125,623	90,680,400 S.P. 42,156,691 H.D. 177,430,225 EQ. Q R.W. 310,267,316	2,844,000 S.P. 42,156,691 H.D. 177,430,225 EQ. Q R.W. 222,430,916	144,598,700 S.P. 360,000,000 H.D. 1,064,581,350 EQ. Q R.W. 1,569,180,050	194.69 S.P. 90.51 H.D. 380.94 EQ. 0.00 R.W. \$666.14 (465,768 kw)	6.11 S.P. 90.51 H.D. 380.94 EQ. 0.00 R.W. \$477.56 (465,768 kw)	48.64 S.P. 121.09 H.D. 358.08 EQ. 0.00 R.W. \$527.81 (2,973,000 kw)	1200 2260
3C. Same as 3A except Phased Piles	2043 Estech 5211 IMC 7254 acres \$8,125,623	90,680,400 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 297,665,625	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	144,598,700 S.P. 250,000,000 H.D. 1,064,581,350 EQ. 22,368,256 R.W. 1,481,548,306	192.94 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$633.33 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	48.20 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W. \$493.85 (3,006,296 kw)	1200 2260
3D. Same as 3C except keep the entire 8260 acres	2043 Estech 6217 IMC 8260 acres \$9,043,527	91,598,304 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 298,583,529	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	145,516,604 S.P. 250,000,000 H.D. 1,064,581,350 EQ. 22,368,256 R.W. 1,482,466,210	194.89 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$635.28 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	48.51 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W. \$494.16 (3,000,000 kw)	1200 2260

S.P. = Site Preparation (includes property cost and Bartow effluent cost)
H.D. = Heat Dissipation Equipment
EQ = Plant Equipment (excludes coal-related costs)
R.W. = Reclaimed Water piped from Mulberry

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included.

FPC POLK COUNTY SITE TABULATION OF COST ALC 55 AND 58

SCENCO-3.XLS 7/16/93 7:34 AM page 3 of 4

Scenario's	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/Ultimate
2000 Mw CGCC Well/Dry Phased Piles Delete P-3 & Phos.	2043 Estech 5211 IMC 7254 acres \$8,125,623	90,680,400 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 297,665,625	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	138,910,700 S.P. 228,750,000 H.D. 709,720,900 EQ. Q R.W. 1,077,381,600	192.94 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$433.33 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	69.77 S.P. 114.89 H.D. 356.46 EQ. 0.00 R.W. \$541.13 (1,991,000 kw)	1200 2260
2000 Mw CGCC Phased Piles Same as 4 except Reclaimed Water	2043 Estech 5211 IMC 7254 acres \$8,125,623	90,680,400 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 297,665,625	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	138,910,700 S.P. 187,500,000 H.D. 709,720,900 EQ. 10,811,295 R.W. 1,046,942,895	192.94 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$433.33 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	69.46 S.P. 93.75 H.D. 354.86 EQ. 5.41 R.W. \$523.47 (2,000,000 kw)	1200 2260
1000 Mw NGCC 1000 Mw CGCC 1200 Pond/Piles Delete P-2, P-3, N-11C, N-11A, Phos, Triangle Lakes N-15	2043 Estech 3922 IMC 5965 acres \$6,164,811	86,963,814 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 293,949,039	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	128,721,424 S.P. 156,250,000 H.D. 709,720,900 EQ. Q R.W. 994,692,324	185.03 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$425.42 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	64.36 S.P. 78.13 H.D. 354.86 EQ. 0.00 R.W. \$497.35 (2,000,000 kw)	1200 1200
1000 Mw NGCC 2000 Mw CGCC 30% Parallel Air- Cooled w/ 1200 Acre Pond	2043 Estech 3062 IMC 5105 acres \$6,164,811	86,963,814 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 293,949,039	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	134,409,424 S.P. 331,250,000 H.D. 1,064,581,350 EQ. Q R.W. 1,530,240,774	185.03 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$425.42 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	45.13 S.P. 111.22 H.D. 357.45 EQ. 0.00 R.W. \$513.80 (2,978,306 kw)	1200 1200
2000 Mw NGCC 1200 Acre Pond/Piles	2043 Estech 3062 IMC 5105 acres \$6,164,811	86,963,814 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 293,949,039	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	123,033,424 S.P. 125,000,000 H.D. 709,720,900 EQ. Q R.W. 957,754,324	185.03 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$425.42 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W. \$446.45 (470,000 kw)	61.52 S.P. 62.50 H.D. 354.86 EQ. 0.00 R.W. \$478.88 (2,000,000 kw)	1200 1200

S.P. = Site Preparation (includes property cost and Barlow effluent cost)
H.D. = Heat Dissipation Equipment
EQ = Plant Equipment (excludes coal-related costs)
R.W. = Reclaimed Water piped from Mulberry

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included

FPC POLK COUNTY SITE TABULATION OF COS, CALC 55 AND 58

SCENCO-3.XLS 7/16/93 7:34 AM Page 4 of 4

Scenario's	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/Ultimate
6. 500 Mw NGCC + 500 Mw CGCC Wet Pond/Piles Delete N-11B N-13 & N-9B from Scenario 5, property	2043 Estech 2113 IMC 4156 acres \$5,298,915	69,666,901 S.P. 29,555,000 H.D. 177,430,225 EQ Q R.W. 276,652,126	42,542,296 S.P. 29,555,000 H.D. 177,430,225 EQ Q R.W. 249,527,521	112,209,197 S.P. 78,125,000 H.D. 354,860,450 EQ Q R.W. 545,194,647	148.23 S.P. 62.88 H.D. 377.51 EQ Q.00 R.W. \$588.62 (470,000 kw)	90.52 S.P. 62.88 H.D. 377.51 EQ Q.00 R.W. \$530.91 (470,000 kw)	112.21 S.P. 78.13 H.D. 354.86 EQ Q.00 R.W. \$545.19 (1,000,000 kw)	600 600
7. 500 Mw NGCC Wet Pond Only use SA-8, SA-9, & SA-13	903 Estech \$1,490,000	39,178,000 S.P. 29,555,000 H.D. 177,430,225 EQ Q R.W. 246,163,225	Not Applicable	39,178,000 S.P. 29,555,000 H.D. 177,430,225 EQ Q R.W. 246,163,225	83.36 S.P. 62.88 H.D. 377.51 EQ Q.00 R.W. \$523.75 (470,000 kw)	Not Applicable	78.36 S.P. 59.11 H.D. 354.86 EQ Q.00 R.W. \$492.33 (800,000 kw)	311 311
7A. 500 Mw NGCC Same as 7 except Dry Cooling	163 Estech \$268,950	30,738,950 S.P. 139,629,134 H.D. 177,430,225 EQ Q R.W. 347,798,309	Not Applicable	30,738,950 S.P. 139,629,134 H.D. 177,430,225 EQ Q R.W. 347,798,309	67.53 S.P. 306.75 H.D. 389.79 EQ Q.00 R.W. \$764.07 (455,194 kw)	Not Applicable	63.48 S.P. 288.34 H.D. 366.40 EQ Q.00 R.W. \$718.22 (484,349 kw)	NA NA
8. 3000 Mw Case A' on Dry Towers	790 Estech 4453 IMC 5243 acres \$2,366,551	101,868,151 S.P. 62,333,577 H.D. 177,430,225 EQ Q R.W. 341,631,953	0 S.P. 62,333,577 H.D. 177,430,225 EQ Q R.W. 239,763,802	103,589,351 S.P. 530,496,528 H.D. 1,064,581,350 EQ Q R.W. 1,698,669,229	223.79 S.P. 136.94 H.D. 389.79 EQ Q.00 R.W. \$750.52 (455,194 kw)	0.00 S.P. 136.94 H.D. 389.79 EQ Q.00 R.W. \$526.73 (455,194 kw)	35.67 S.P. 182.68 H.D. 366.59 EQ Q.00 R.W. \$584.94 (2,904,000 kw)	NA NA
9. Case A' Lower Floridan Makeup Add 2500 acre brine pond to JA property	2043 Estech 2211 IMC 9754 acres \$10,406,698	99,526,698 S.P. 59,110,000 H.D. 177,430,225 EQ Q R.W. 336,066,923	0 S.P. 59,110,000 H.D. 177,430,225 EQ Q R.W. 236,540,225	187,668,617 S.P. 503,063,830 H.D. 1,064,581,350 EQ Q R.W. 1,755,313,797	218.31 S.P. 129.66 H.D. 389.19 EQ Q.00 R.W. \$737.15 (455,900 kw)	0.00 S.P. 129.66 H.D. 389.19 EQ Q.00 R.W. \$518.84 (455,900 kw)	64.49 S.P. 172.87 H.D. 365.84 EQ Q.00 R.W. \$603.20 (2,910,000 kw)	1200 2260

S.P. = Site Preparation (includes property cost and Barlow effluent cost)
H.D. = Heat Dissipation Equipment
EQ = Plant Equipment (excludes coal-related costs)
R.W. = Reclaimed Water piped from Mulberry

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included.

FPC POLK COUNTY SITE TABULATION OF COSTS - CALC 55 AND 58

SCENCOS3.XLS 7/24/93 6:37 PM Page 2 of 2

Scenario's	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/Ultimate
0 Mw NGCC et Pond ly use SA-8, -9, & SA-13 andon Bartow eline	903 Estech \$1,490,000	45,522,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 252,507,225	Not Applicable	45,522,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 252,507,225	96.86 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$537.25 (470,000 kw)	Not Applicable	91.04 S.P. 59.11 H.D. 354.86 EQ. Q.00 R.W. \$505.01 (500,000 kw)	311 311
00 MW GCC et Pond Piles	2043 Estech \$3,370,950	66,054,820 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 273,040,045	2,390,667 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,375,892	70,836,153 S.P. 88,665,000 H.D. 532,290,675 EQ. Q R.W. 691,791,828	140.54 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$580.94 (470,000 kw)	5.09 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$445.48 (470,000 kw)	47.22 S.P. 59.11 H.D. 354.86 EQ. Q.00 R.W. \$461.19 (1,800,000 kw)	722 722
00 Mw NGCC e 7B Except ep All Property ompatible h 3000 MW ldout)	2043 Estech 6217 IMC 8260 acres \$9,043,527	71,727,397 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 278,712,622	2,390,667 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,375,892	76,508,730 S.P. 88,665,000 H.D. 532,290,675 EQ. Q R.W. 697,464,405	152.61 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$593.01 (470,000 kw)	5.09 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$445.48 (470,000 kw)	51.0 [*] S.P. 59.11 H.D. 354.86 EQ. Q.00 R.W. \$464.98 (1,800,000 kw)	600 1200

* = Site Preparation (includes property cost and Bartow effluent cost)
D = Heat Dissipation Equipment
= Plant Equipment (excludes coal-related costs)
V = Reclaimed Water piped from Mulberry

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included.

Scenario's	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/Ultimate
as JC pt keep ntire 8260	2043 Estech 6212 IMC 8260 acres \$9,043,527	91,598,304 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 298,583,529	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	145,516,604 S.P. 250,000,000 H.D. 1,064,581,350 EQ. 22,368,256 R.W. 1,482,466,210	194.89 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$635.28 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$446.45 (470,000 kw)	48.51 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W. \$494.16 (3,000,000 kw)	1200 2260
Mw NGCC Pond	2043 Estech 2112 IMC 4156 acres \$5,298,915	69,666,901 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 276,652,126	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	75,354,901 S.P. 88,665,000 H.D. 532,290,660 EQ. Q R.W. 696,310,561	148.23 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$588.62 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$446.45 (470,000 kw)	50.24 S.P. 59.11 H.D. 354.86 EQ. Q.00 R.W. \$464.21 (1,800,000 kw)	700 700
Mw NGCC s.A. Except All Property Compatible Case A)	2043 Estech 6212 IMC 8260 acres \$9,043,527	73,411,513 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 280,396,738	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. Q R.W. 209,829,225	79,099,513 S.P. 88,665,000 H.D. 532,290,660 EQ. Q R.W. 700,055,173	156.19 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$596.59 (470,000 kw)	6.05 S.P. 62.88 H.D. 377.51 EQ. Q.00 R.W. \$446.45 (470,000 kw)	52.73 S.P. 59.11 H.D. 354.86 EQ. Q.00 R.W. \$466.70 (1,800,000 kw)	700 700

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included.

Site Preparation (includes property cost and Barlow effluent cost)
Heat Disposition Equipment
Plant Equipment (excludes coal-related costs)
Reclaimed Water piped from Mulberry

FPC POLK COUNTY SITE TABULATION OF COSTS

SCEN3D3E.XLS 8/28/93 3:54 PM Page 1 of 1

Scenario	Property Requirements (Acres) (\$)	Initial Capital Cost For First 470 Mw (\$)	Initial Capital Cost For Second 470 Mw (\$)	Total Capital Cost For Ultimate Buildout (\$)	Installed Cost \$ per kw For First 470 Mw	Installed Cost \$ per kw For Second 470 Mw	Average Cost \$ per kw For Ultimate Site Devp	Cooling Pond Acres Initial/ Ultimate
3D. Case A* Phased piles 3000 MW 1000 MW NGCC 2000 MW CGCC	2043 Estech 6217 IMC 8260 acres	93,300,604 S.P. 29,555,000 H.D. 177,430,225 EQ. 0 R.W.	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. 0 R.W.	136,220,527 S.P. 250,000,000 H.D. 1,084,581,350 EQ. 22,368,256 R.W.	198.51 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W.	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W.	45.41 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W.	1200 2260
	\$9,043,527	300,285,829	209,829,225	1,473,170,133	\$638.91 (470,000 kw)	\$446.45 (470,000 kw)	\$491.06 (3,000,000 kw)	
3E. Alternative 1B Phased piles 3000 MW 1000 MW NGCC 2000 MW CGCC	2043 Estech 6217 IMC 8260 acres	76,397,282 S.P. 29,555,000 H.D. 177,430,225 EQ. 0 R.W.	2,844,000 S.P. 29,555,000 H.D. 177,430,225 EQ. 0 R.W.	152,182,205 S.P. 250,000,000 H.D. 1,084,581,350 EQ. 22,368,256 R.W.	162.55 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W.	6.05 S.P. 62.88 H.D. 377.51 EQ. 0.00 R.W.	50.73 S.P. 83.33 H.D. 354.86 EQ. 7.46 R.W.	722 2260
	\$9,043,527	283,382,507	209,829,225	1,489,131,811	\$602.94 (470,000 kw)	\$446.45 (470,000 kw)	\$496.38 (3,000,000 kw)	

S.P. = Site Preparation (includes property cost and Barlow effluent cost)
H.D. = Heat Dissipation Equipment
EQ. = Plant Equipment (excludes cost-related costs)
R.W. = Reclaimed Water piped from Mulberry

* = Could be same as A version.
Costs in 1993 dollars.
Transmission line and substation costs
are not included.

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ATTACHMENT III

COMPARISON OF RECENTLY CONSTRUCTED

POWER PLANT PROJECTS

Dist 3/14/93

COMPARISON OF POWER PROJECTS

	TEC Polk	TEC Haden	Cypress	Indiantown	Cedar Bay	Martin	S/RPP	Lauderdale	Peace Cogen	Orlando Cogen	Midberry Energy	Lake Cogen Usamilla	Confidential
Estl	IGCC Refuse Coal No. 2 No. 2	NG No. 2 Byogas	Coal No. 2 ^a	Coal No. 2/Gas	Coal Bark ¹ /No. 2 ^a	NG No. 2 Coal	Coal No. 2 ^a	NG No. 2	NG No. 2	NG	NG No. 2	NG No. 2	NG No. 2
Capacity (MW/Type)	220 IGCC 1,150 ^b	295/440 CC 660 CC	832 PC ^c	330 PC	275 ^d	2,400 ^e 3,200 ^f	1,372 PC	684 CC ^g	108 CC	115 CC	117 CC	108 CC	1,000 CC
Site Size (Ac)	4,348	1,308	1,925	229	425 ^h	11,300	1,656	392 ⁱ	< 10 ^j	< 10 ^j	< 10 ^j	< 10 ^j	865
Heat Disposition	Cooling Pond	Cooling Pond	Mech Draft Wet Towers	Mech Draft Wet Towers	Mech Draft Wet Towers	Cooling Pond	Hot Draft Wet Towers	Once through	Wet Towers	Wet Towers	Wet Towers	Wet Towers	Mech Draft Dry Towers
Type	727	570		Zero Disch	Zero Disch	6,500 ^d			Zero Disch		Zero Disch	Zero Disch	Zero Disch
Pond Size (Ac)													
Water (MGD)(Avg/Peak)	6.6/9.3 ^m Total Use	3.8/8.7 ⁿ Total Use	10.8/11.3 ^m Total Use	1 1/4 ^g	unk/1.5 Process	28.6/44.6 Total Use	3.8/7.8 Process Use	1.6/9.0 Process Use	Unk/0.9 Total Use	Unk/1.3 Total Use	Unknown	Unk/0.9 Total Use	0.4/2.0 ^o
Groundwater (Permitted)													
Surface Water (Permitted)				4 1/4 ⁷			17.3/18.4 HD from effluent						
Air Source													
(OPM/MW)	4.0/5.6	4.0/9.1	9.0/9.4	8.6/9.9	N/A	6.3/9.7	N/A	N/A	Unk/8.4	Unk/11.3		Unk/8.4	0.2/1.4
Cost (\$/KW)	1,768 ^p	542 ^q	1,500	1,683	1,636	842 (295 ^r)	1,300	473	1,000	1,000	1,000	1,000	< 600

- a Permit request based on well capacity, not plant requirement
- b Surface water is primary source; ground water is backup
- c Projected for Martin 5 & 6 CC
- d Pond placed in service at full size to handle ultimate capacity
- e No. 2 Fuel Oil for startup and flame stabilization
- f Bark as supplemental fuel ≤ 10% total heat input
- g TEC Polk capacity (MW) 260 IGCC, 440 CC, 450 GT; Cost on IGCC
- h Cedar Bay capacity (MW) 256 CFB, not to grid
- i 1,600 Conventional plus 800 CC; Ultimate adds 800 CC w/Coal Gas for 1,600

- j Winter rating
- k Cedar Bay total site; 35 acres for new capacity
- l Lauderdale site already owned
- m Water Use not yet permitted, but applied for
- n Cypress SCA withdrawn
- o Martin 3 & 4
- p Minimal site size - projected less than 10 acres
- q Includes a simple cycle unit, does not include cooling pond development or site property cost
- r Source for water not decided

COMPARISON OF POWER PROJECT COST

	TEC Pull	TEC Harder	Cypress	Indiantown	Cedar Bay	Martin	S/RPP	Lauderdale	Pasco Cogen	Orlando Cogen	Midberry Energy	Lake Cogen	Confidential
Capital Cost	\$109M		\$1,300M	\$505M			\$1,600M	\$460M ^d					
Cost \$/KW	1,768	542	1,500	1,683	1,636	280 ^c 842 ^b	1,164	673	1,000	1,000	1,000	1,000	< 600 ^f (550-700) ^f
Year Basis	1996		1/88	1/91		1997 ^a 1993 ^b	1979	1992					1994
Includes:													
Equipment	220 KCCC	295 GT	832 PC	330 PC	256 CFB	2x435NGCC ^a 2x470NGCC ^b	1,372 PC	392 CC Repowering boilers & demolition					1,000 CC
Land (acres)	?		?	229			1,556						865
T-Line	?	?	?	30 mi water pipeline		230 KV Upgrade (12 mi)	230KV T-Line (44 mi)						?
Gas Line						NO Lateral (12 mi)							No Lateral
Other	\$100M DOE ^c						Martin Cool Turn.						
Excludes:		Cooling Pond Land Purchase		T-Line	Land Purchase	Cooling Pond Land Purchase		T-Line Land Purchase					
Source	Head Order	FPC	Head Order	Head Order	Atty	Ebasco	Ebasco	Ebasco	FPC	FPC	FPC	FPC	Ebasco

^a Martin 3&4 actual
^b Martin 5&6 per BRP
^c TEC Pull; DOE share includes \$11.5M for HOCV
^d Lauderdale actual cost
^e Target capital cost
^f Planning capital cost range

ATTACHMENT IV

12/30/93 CAPITAL COST ESTIMATES

31-Dec-93

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ATTACHMENT V

O&M COST COMPARISONS

OPERATING & MAINTENANCE COST ESTIMATE

COMPLIANCE	POLK COUNTY SITE						COMPETITIVE UNITS			
	First 470 MW		Second 470 MW		Full 940 MW		470 MW (487.2) (Certified)		220 MW (218.7) (Non-Certified)	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
CEMS										
Responsible party: FPC	\$180,000	0.38	\$180,000	0.38	\$360,000	0.38	\$180,000	0.38	\$80,000	0.41
Annual Air Compliance Tests										
Responsible party: FPC	\$180,000	0.32	\$150,000	0.32	\$300,000	0.32	\$150,000	0.32	\$75,000	0.34
Air Pollution Fees										
Responsible party: FPC	\$38,120	0.08	\$38,120	0.08	\$72,240	0.08	\$38,120	0.08	\$18,000	0.08
Annual Dam Inspection										
Responsible party: FPC	\$15,000	0.03	\$0	0.00	\$15,000	0.02	N/A	N/A	N/A	N/A
Waste Stream Characterization										
Responsible party: FPC	\$840	0.00	\$0	0.00	\$840	0.00	N/A	N/A	N/A	N/A
Ground Water Monitoring										
Responsible party: FPC	\$78,440	0.17	\$0	0.00	\$78,440	0.08	\$100,440	0.21	\$50,220	0.23
Reclamation/ Reporting										
Responsible party: FPC	\$100,001	0.21	\$0	0.00	\$100,001	0.11	N/A	N/A	N/A	N/A
Hazardous Materials Reporting										
Responsible party: FPC	\$400	0.00	\$0	0.00	\$400	0.00	\$400	0.00	\$400	0.00
Water Use Monitoring/Reporting										
Responsible party: FPC	\$18,000	0.03	\$0	0.00	\$18,000	0.02	\$18,000	0.03	\$0	0.00
Field Permeability Testing/SWDA										
Responsible party: FPC	\$8,175	0.02	\$0	0.00	\$8,175	0.01	N/A	N/A	N/A	N/A
Potable Water Testing										
Responsible party: FPC	\$8,100	0.01	\$0	0.00	\$8,100	0.01	\$8,100	0.01	N/A	N/A
NPDES Monitoring/Reporting										
Responsible party: Ebasco	\$0	0.00	\$0	0.00	\$0	0.00	\$18,000	0.02	N/A	N/A
IWW Monitoring										
Responsible party: Ebasco	\$317	0.00	\$834	0.00	\$851	0.00	\$317	0.00	\$317	0.00
MSSW Monitoring										
Responsible party: Ebasco	\$0	0.00	\$0	0.00	\$0	0.00	\$34,820	0.07	\$0	0.00
Domestic Wastewater System										
Responsible party: FPC	\$4,408	0.01	\$0	0.00	\$4,408	0.00	\$4,408	0.01	N/A	N/A
Ambient Air Monitoring										
Responsible party: FPC	\$188,841	0.35	\$0	0.00	\$188,841	0.18	\$0	0.00	\$0	N/A
COMPLIANCE TOTAL	\$784,310	1.83	\$388,754	0.78	\$1,131,084	1.20	\$538,073	1.15	\$233,887	1.07

OPERATING & MAINTENANCE COST ESTIMATE

	POLK COUNTY SITE						COMPETITIVE UNITS			
	First 470 MW		Second 470 MW		Full 940 MW		470 MW (467.2) (Certified)		220 MW (218.7) (Non-Certified)	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
POWER PLANT										
Fuel (responsible party: FPC)	\$50,024,004	108.43	\$50,024,004	108.43	\$100,048,100	108.43	\$51,376,640	108.80	\$24,041,290	108.80
Power system - Boilers (responsible party: Ebasco)	\$210,795	0.46	\$210,795	0.46	\$421,570	0.46	\$210,795	0.46	\$117,431	0.54
Power system - Steam Turbines (responsible party: Ebasco)	\$272,511	0.58	\$272,511	0.58	\$545,022	0.58	\$272,511	0.58	\$141,958	0.65
Power system - Gas Turbines (responsible party: FPC)	\$1,000,000	2.13	\$1,000,000	2.13	\$2,000,000	2.13	\$1,000,000	2.14	\$700,000	3.20
Power system - Auxiliary Equipment, Electric Switchgear & Controls (responsible party: Ebasco)	\$220,000	0.47	\$220,000	0.47	\$440,000	0.47	\$220,000	0.47	\$108,247	0.48
Power system - Annual Outage (responsible party: Ebasco)	\$303,200	0.65	\$304,200	0.65	\$608,400	0.65	\$304,200	0.65	\$202,285	0.92
Power system - Purchasing (responsible party: FPC)	\$53,587	0.11	\$53,587	0.11	\$107,184	0.11	\$53,587	0.11	\$45,567	0.21
Condenser Cooling System (responsible party: Ebasco)	\$28,821	0.00	\$28,821	0.00	\$58,242	0.00	\$28,821	0.00	\$16,944	0.07
Condenser cooling-Backpressure Penalty (responsible party: Ebasco)	0 MW	0.00	0 MW	0.00	0 MW	0.00	2.3 MW	0.00	1.1 MW	0.00
Condenser cooling-Auxiliary Power (responsible party: Ebasco)	0 MW	0.00	0 MW	0.00	0 MW	0.00	0.5 MW	0.00	0.2 MW	0.00
Cooling Water Supply (responsible party: Ebasco)	\$471,000	1.00	\$78,500	0.17	\$548,500	0.58	\$0	0.00	\$0	0.00
Process Water Supply (responsible party: Ebasco)	\$114,387	0.24	\$114,387	0.24	\$228,775	0.24	\$114,387	0.24	\$81,388	0.37

OPERATING & MAINTENANCE COST ESTIMATE

	POLK COUNTY SITE						COMPETITIVE UNITS			
	First 470 MW		Second 470 MW		Full 940 MW		470 MW (487.2) (Certified)		220 MW (210.7) (Non-Certified)	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
SITE MANAGEMENT										
Security										
Responsible party: FPC	\$75,000	0.10	\$0	0.00	\$75,000	0.08	\$75,000	0.10	\$75,000	0.34
Cooling Pond/Cooling Tower										
Responsible party: Ebasco	\$0	0.00	\$0	0.00	\$0	0.00	\$375,000	0.00	\$187,500	0.00
Brine Pond										
Responsible party: FPC	\$20,000	0.04	\$0	0.00	\$20,000	0.02	\$0	0.00	\$0	0.00
SWDA										
Responsible party: FPC	\$20,030	0.00	\$0	0.00	\$20,030	0.03	\$0	0.00	\$0	0.00
Plant Island (SA-11, SA-12 & SA-13)										
Responsible party: Ebasco	\$60,520	0.15	\$0	0.00	\$60,520	0.07	\$23,010	0.05	\$23,010	0.11
Water Crop System										
Responsible party: FPC	\$40,000	0.00	\$0	0.00	\$40,000	0.02	N/A	N/A	\$0	0.00
Dam Maintenance										
Responsible party: Ebasco	\$130,430	0.20	\$0	0.00	\$130,430	0.15	N/A	N/A	N/A	N/A
Mowing										
Responsible party: Ebasco	\$110,305	0.25	\$0	0.00	\$110,305	0.12	\$15,300	0.03	\$15,300	0.07
Weed and Exotics Control										
Responsible party: FPC	\$4,971	0.01	\$0	0.00	\$4,971	0.01	N/A	N/A	N/A	N/A
Dam Surveillance										
Responsible party: Ebasco	\$33,040	0.07	\$0	0.00	\$33,040	0.04	N/A	N/A	N/A	N/A
SITE MANAGEMENT TOTAL	\$523,297	1.11	\$0	0.00	\$523,297	0.50	\$480,370	1.05	\$300,870	1.30

OPERATING & MAINTENANCE COST ESTIMATE

	POLK COUNTY SITE						COMPETITIVE UNITS			
	First 470 MW		Second 470 MW		Full 940 MW		470 MW (407.2) (Certified)		220 MW (210.7) (Non-Certified)	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
Process Wastewater Treatment										
Responsible party: El Paso	\$0	0.00	\$0	0.00	\$0	0.00	\$85,000	0.18	\$0	0.00
Process Waste Disposal										
Responsible party: FPC	\$13,872	0.03	\$0	0.00	\$13,872	0.01	\$178,420	0.38	\$80,715	0.41
Potable Water Supply - Onsite										
Responsible party: FPC	\$37,410	0.08	\$0	0.00	\$37,410	0.04	\$37,410	0.08	\$20,000	0.09
Sanitary Wastewater Disposal										
Responsible party: FPC	\$7,884	0.02	\$0	0.00	\$7,884	0.01	\$7,884	0.02	\$12,000	0.05
Solid Waste Disposal										
Responsible party: El Paso	\$40,950	0.06	\$40,950	0.08	\$81,900	0.08	\$40,950	0.08	\$20,475	0.08
Property Taxes										
Responsible party: El Paso	\$3,870,000	8.45	\$3,810,000	8.11	\$7,780,000	8.28	\$3,820,000	8.18	\$1,810,120	8.73
POWER PLANT TOTAL	\$6,748,200	14.35	\$6,134,552	13.05	\$12,880,940	13.70	\$8,378,855	13.85	\$3,483,098	15.83

Operating & Maintenance Total	\$8,833,905	17.00	\$8,501,308	13.83	\$14,535,210	15.40
\$ / Megawatt Hour **	\$2.50		\$2.82		\$2.20	
O & M Total Including Fuel	\$68,057,000	108.17	\$58,525,400	107.21	\$114,583,300	108.10
\$ / Megawatt Hour **	\$18.00		\$17.80		\$17.84	

\$7,404,000	15.85	\$3,987,805	18.20
\$2.31		\$2.80	
\$58,778,844	112.18	\$28,047,283	112.41
\$18.30		\$18.88	

Assuming the same capacity factor for competition

** megawatt hours - 470 MW * 8760 * .78CF = 3,211,416 MWH/yr or 1,603,216 MWH/yr for 220 MW unit

Planning model:

$$\frac{8033905 - 3970000}{470,000} + \frac{1,330,000}{470,000}$$
 ↑
 capital component

$$\frac{4,063,000 - 500,000}{1,300,000}$$
 recurring capital

**FLORIDA POWER CORPORATION
POLK COUNTY SITE
Operating & Maintenance Cost Estimate
Assumptions**

Page 1 of 5
2/7/94

Compliance

	Polk County Site	Competitive Units
Continuous Emission Monitoring System	Per Condition XIII, (page 2 of ESD report).	CEMS requirements similar to Polk Site.
Annual Air Compliance	Per Condition XIII, (page 1 of ESD report).	Testing requirements similar to Polk Site.
Air Pollution Fees	Per Condition XXII.B, (page 8 of ESD report).	Required by Clean Air Act.
Annual Dam Inspection	Per Condition XVII.H, (page 5 of ESD report), 3rd party inspection by Florida P.E.	No impoundments requiring inspection.
Waste Stream Characterization	Per Condition XV, (page 3 of ESD report), used annual wastewater analysis only, refer to Domestic Wastewater System (Compliance) and Sanitary Wastewater Disposal (Plant) for balance of costs.	N/A
Groundwater Monitoring	Per Conditions XVII and XVIII, (page 6 of ESD report), includes quarterly well sampling, well & pond sampling, refer to Field Permeability (Compliance) and Process Waste Disposal (Plant) for balance of costs.	Expect similar requirements of competitors.
Reclamation / Reporting	Conditions XXIV, XXV.F.7, and XXX.16 have been levelized for life of plant, (pages 11 and 12 of ESD report). Includes wetland mitigation and wildlife habitat management plans.	N/A
Hazardous Materials Program	Per Condition XXX.10, (page 13 of ESD report), Includes training, drills, record keeping, updates, reporting and program coordination for Emgcy Resp and SPCC Plans. Chemicals application include fuel oil and water treatment.	Both 470 and 220 MW units will have fuel oil storage and process/cooling water treatment. They will require a program similar in scale to Polk Site.
Water Use Monitoring & Reporting	Monthly, quarterly, and annual read & reporting for DEP, SWFWMD, and Polk County, (page 9 of ESD report), includes reporting and .2FTE, Balance of costs included under Site Management responsibilities.	Same as for Polk Site. 220 MW unit on City water.
Field Permeability Testing / SWDA	Condition XVII.6.2 has been levelized for life of plant plus Condition XXI, (pages 6 and 7 of ESD report), includes clay permeability test and SWDA leachate analysis with .1FTE salary.	Not required.

Potable Water Testing	Per Condition XVI.C, (page 4 of ESD report), includes certified operator, annual water analysis, and 9 yr. compl. analysis, refer to Potable Water Supply (Plant) for balance of costs.	470 MW has similar requirement. 220 MW has no requirement due to City supply.
NPI/DES Monitoring & Reporting	Not required due to Zero Discharge site design.	470 MW has 1 industrial wastewater outfall & 1 storm water discharge. 220 MW has no discharge to surface water requiring permit.
IWW Monitoring	Required for metal cleaning waste.	Same as for Polk Site.
MSSW Monitoring	Not required due to Zero Discharge site design.	Both 470 and 220 MW units will require this to meet Class III standards.
Domestic Wastewater System	Per Condition XV, (page 3 of ESD report), includes annual sludge analysis and certified plant operator, refer to Waste Stream Characterization (Compliance) and Sanitary Wastewater Disposal (Plant) for balance of costs.	Similar to Polk Site for 470 MW. N/A for 220 MW.
Ambient Air Monitoring	Per Condition XXX.18, (page 14 of ESD report).	Not required.

Site Management

	Polk County Site	Competitive Units
Security	Round the clock shifts.	Same as Polk County.
Cooling Pond / Cooling Tower	Exclusive of dams.	Towers only, as a percent of capital cost.
Brine Pond	1/2 man year operations	N/A
SWDA	1/2 man year operations, plus sampling, collecting and reporting.	N/A
Plant Island	Road screen & mowing.	Road screen & mowing.
Water Crop System	1 full-time operator.	N/A
Dam Maintenance	Monthly read 200 piezometer; fertilize twice per year. Includes mowing, erosion control, and fertilization of berms around cooling pond only.	N/A
Mowing	Remainder of site dams, 17 times per year.	Plant Island, 17 times per year.
Nuisance & Exotics	Conditions XXIV.1.2 and XXV.F.4 have been levelized for the life of plant, (page 10 of ESD report).	N/A
Dam Surveillance	Daily inspections .	N/A

Power Plant

Fuel	SunShine for Polk Site	FGT for Competitive Units
Power System	Based on routine maintenance and annual outage. Includes site personnel annual salaries (20 people rough estimate).	470MW unit is GE Frame 7FA 2 GT on 1 ST. 220MW unit is GE Frame 7FA 1 GT on 1 ST.
Boilers	2 HRSG's.	1 HRSG-220MW unit, 2 HRSG-470MW unit.
Steam Turbines	1 steam turbine.	1 steam turbine.
Gas Turbines	2 gas turbines.	1 GT-220MW unit, 2 GT-470MW unit.
Auxiliary Equipment, Electric and Switchgear, Controls		Competitor equipment is similar.
Annual Outage		Contracted labor.
Purchasing	Includes plant supplies and expendables.	Includes plant supplies and expendables.
Condenser		
Cooling System	Cooling pond.	Wet mechanical draft cooling towers.
Backpressure Penalty	Based on difference in condenser inlet - Base case.	Differential.
Auxiliary Power	Base case.	Fans, pumping head.
Water Supply		
Cooling Water Supply	Water crop and reclaimed wastewater. Lime softening & RO.	Ground water. No treatment.
Process Water Supply	Demineralizer.	Demineralizer.
Process Wastewater Treatment	Solids removal and neutralization; treated water to the cooling pond.	470MW on-site treatment for NPDES discharge. 220MW pretreat for discharge to municipal POT.
Process Waste Disposal	Per Conditions XVII and XVIII, (page 6 of ESD report), includes .2FTE salary, solids from water & wastewater treatment sent to the SA-8 SWDA.	All process wastes disposed off site
Potable Water Supply - Onsite	Per Condition XVI.C, (page 4 of ESD report), includes FATE salary, calif. flow meter, and chemicals, refer to Potable Water Testing (Compliance) for balance of costs.	Similar conditions

Power Plant - continued		
Sanitary Wastewater Disposal	Per Condition XV, (page 3 of ESD report), includes flow meter calif., chemicals, and sludge disposal costs., refer to Waste Stream Characterization (Compliance) and Domestic Wastewater System (Compliance) for balance of costs.	N/A
Solid Waste Disposal	Solids from water & wastewater treatment sent to the SA-8 SWDA.	All process wastes disposed off site.

ATTACHMENT VI

PLANNING STUDIES

OPTIONS 1, 2, AND 3

COMPARISON OF POLK COUNTY CONSTRUCTION OPTIONS 1, 2 and 3

Assumptions:

- DSM goals planning optimized base case.
- Updated capacity, heat rate and cost data for Higgins and Turner full repowering.
- Medium Fuel and Demand and Energy Forecast.
- Siemens CT in-service January, 1996.
- SunShine Pipeline available to Anclote in 1996.
- The incurred/committed cost of the Polk Site is \$64/kW.

Option 1:

Polk Units 1 and 2 are built as planned with November 1998 and 1999 in-service. Capital cost for these units is \$569/kW (1993 \$), the cost of Polk units 3 and 4 are \$487/kW.

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Polk Unit 1 Combined Cycle	235
2000	Polk Unit 2 Combined Cycle	235
2001	Higgins Steam Repowering	249
2002	Turner Steam Repowering	498
2003	No additions	
2004	Higgins Steam Repowering	124
2004	Polk Unit 3 Combined Cycle	235
2005	Polk Unit 4 Combined Cycle	235

Option 2:

Option 2 is the same as Option 1 with the exception of the site size. A small Polk Site is selected changing the cost of Polk Units 1 and 2 to \$526/kW. However, the cost of two future combined cycle units at an undetermined postage stamp site becomes \$558/kW.

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Polk Unit 1 Combined Cycle	235
2000	Polk Unit 2 Combined Cycle	235
2001	Higgins Steam Repowering	249
2002	Turner Steam Repowering	498
2003	No additions	
2004	Higgins Steam Repowering	124
2004	Combined Cycle (postage stamp)	235
2005	Combined Cycle (postage stamp)	235

Option 3:

The Turner and Higgins repowering projects are moved to 1998 and 1999. Future combined cycle units are assumed to be built at smaller sites, their capital cost is now \$558/kW (1993 \$).

Capacity additions are:

<u>Year</u>	<u>Unit</u>	<u>MW</u>
1999	Higgins Steam Repowering	249
2000	Turner Steam Repowering	498
2001	Unit 1 Combined Cycle	235
2002	Unit 2 Combined Cycle	235
2003	No Additions	
2004	Higgins Steam Repowering	124
2004	Unit 3 Combined Cycle	235
2005	Unit 4 Combined Cycle	235

Comparison:

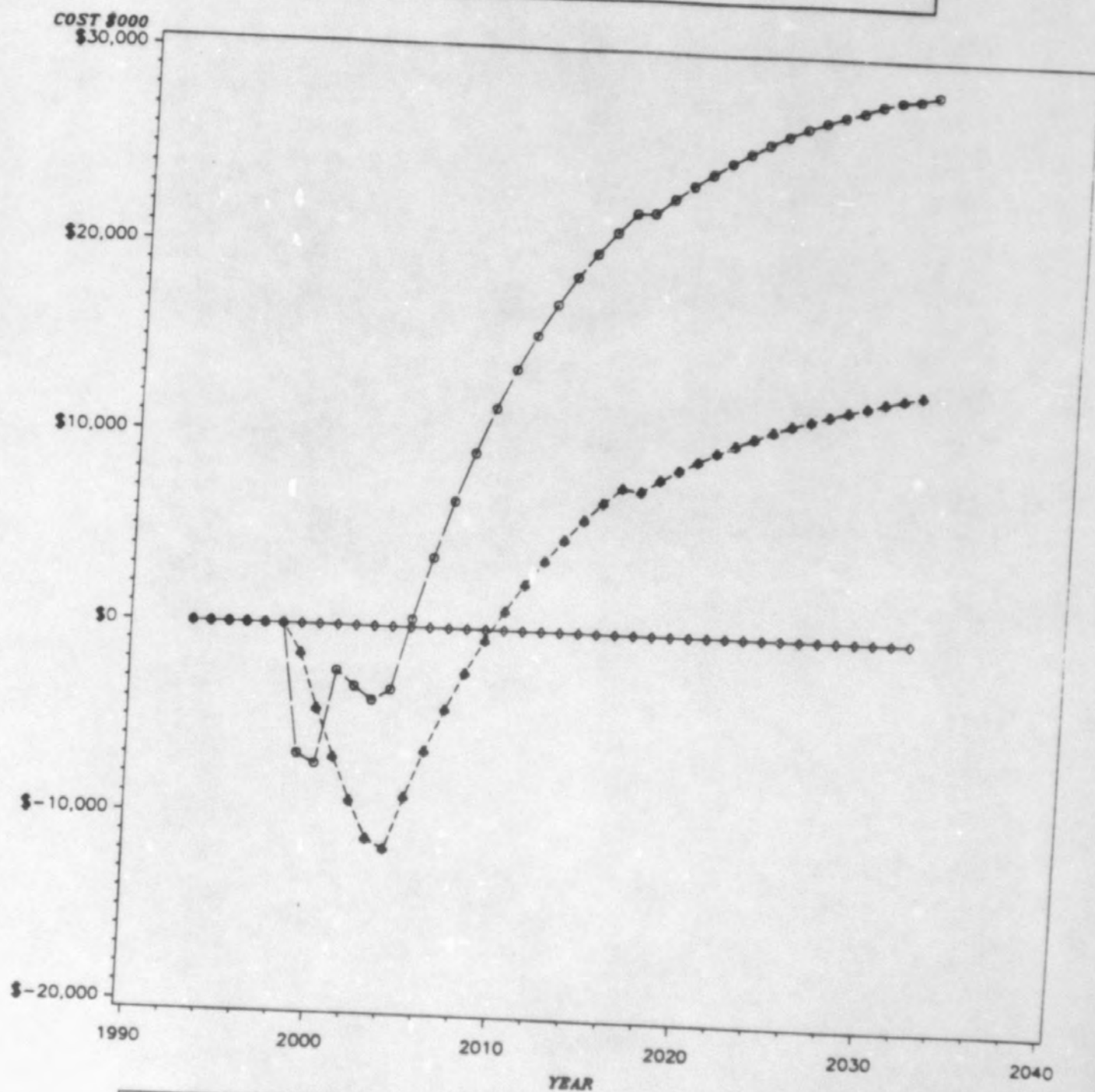
The difference in the cumulative present worth revenue requirements for Options 1, 2 and 3 is shown on the attached graph (Comparison of CPWRR). Option 1 is the selected base case and is represented by the zero line. The differential CPWRR for Options 2 and 3 are then compared to Option 1. By 2004, Option 2 has a CPWRR that is \$11,671,000 lower than Option 1 and Option 3 is \$3,315,000 lower than Option 1. However, by 2010, Option 2 is \$1,025,000 higher than Option 1 and Option 3 is \$13,715,000 higher than Option 1. Options 2 and 3 continue to have higher CPWRR's over the life of the study (2032).

Option 1 is the lowest cost option to construct four gas fired combined cycle units. This advantage is obtained due to the lower incremental costs involved in constructing Units 3 and 4 at the Polk County Site. There are continued savings if the Polk County Site is expanded further.

Options 2 and 3 are the lowest cost options if no additional units beyond Polk 1 and 2 are assumed.

COMPARISON OF CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS

EXTENDED PLAN - INCLUDING C.C. 3 & 4 IMPACTS



RUN:
 OPTION 1-BPS
 OPTION 3-REPOWER
 OPTION 2-LPS

POLK COUNTY SITE STUDY

BASE = PS930694 ... CASE 1 = PS930695
 CASE 2 = PS930696

POLK COUNTY SITE REVIEW

2/17/94

COST	470 MW BLOCK	OPTION 1 BIG POLK SITE	OPTION 2 LITTLE POLK SITE	OPTION 3 REPOWER SITE
	FIRST	569	526	526
SITE/EQUIPMENT		0	0	32
ADDITIONAL SITING		569	526	558
* STUDY COST (\$/KW)		64	64	64
INCURRED/COMMITMENT		633	590	622
PROJECT COST (\$/KW)		2.5	2.31	2.31
* O&M COST (\$/MWH)		0	.5%	.5%
* HEATRATE PENALTY		0	0	0
* GAS FIX PENALTY				

COST	470 MW BLOCK	OPTION 1 BIG POLK SITE	OPTION 2 LITTLE POLK SITE	OPTION 3 REPOWER SITE
	SECOND	476	526	526
SITE/EQUIPMENT		11	32	32
ADDITIONAL SITING		487	558	558
* STUDY COST (\$/KW)		0	0	0
INCURRED/COMMITMENT		487	558	558
PROJECT COST (\$/KW)		2.02	2.31	2.31
* O&M COST (\$/MWH)			.5%	.5%
* HEATRATE PENALTY		0	.5%	.5%
* GAS FIX PENALTY				

NOTES:

* = INPUT DATA FOR STUDY

COST INFORMATION

INCURRED/COMMITMENT \$30 MILLION = \$64/KW
 OPT 2,3 ADDITIONAL SITING \$15 MILLION = \$32/KW
 OPT 1 ADDITIONAL SITING \$5 MILLION = \$11/KW

TRANSMISSION BENEFITS FOR POLK ARE NOT INCLUDED
 GAS LATERAL BENEFITS FOR POLK ARE NOT INCLUDED

ATTACHMENT VII

IMPACTS OF POLK 1 AND 2

DISPLACEMENT BY

PURCHASE POWER

**Purchased Power Payments for Option 3 - Repower
CC Units 1&2
Using Value of Deferral Method**

Year	Total O&M Cost	Total Capital Cost	Total Cap & O&M Cost
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	0	0	0
1998	0	0	0
1999	0	0	0
2000	0	0	0
2001	4,808,553	15,347,577	20,156,130
2002	9,920,046	32,030,393	41,950,438
2003	10,232,527	33,423,715	43,656,242
2004	10,554,852	34,877,646	45,432,498
2005	10,924,272	36,377,385	47,301,657
2006	11,287,504	37,941,613	49,229,116
2007	11,662,847	39,573,102	51,235,948
2008	12,050,705	41,274,745	53,325,451
2009	12,451,498	43,049,559	55,501,058
2010	12,865,656	44,900,690	57,766,349
2011	13,293,632	46,831,420	60,125,052
2012	13,735,882	48,845,171	62,581,053
2013	14,192,885	50,945,514	65,138,398
2014	14,665,135	53,136,171	67,801,305
2015	15,153,142	55,421,026	70,574,168
2016	15,657,433	57,804,130	73,461,563
2017	16,178,553	60,289,708	76,468,260
2018	16,717,065	62,882,165	79,599,230
2019	17,273,551	65,586,098	82,859,650
2020	17,848,614	68,406,300	86,254,914
2021	18,442,873	71,347,771	89,790,645
2022	19,056,973	74,415,726	93,472,699
2023	19,691,578	77,615,602	97,307,179
2024	20,347,373	80,953,073	101,300,446
2025	21,025,069	84,434,055	105,459,123
2026	21,725,398	88,064,719	109,790,117
2027	22,449,119	91,851,502	114,300,621
2028	23,197,016	95,801,117	118,998,132
2029	23,969,897	99,920,585	123,890,481
2030	23,640,256	105,523,930	129,164,186
2031	12,192,462	55,057,110	67,249,573

Assumptions for Polk County Combined Cycle Units

Year of the Avoided Units - Unit 1 = 2001, Unit 2 = 2002
 Avoided Unit Size = 235 MW Each
 Total Installed Plant in 1993 Dollars = \$558/KW Each
 Fixed O&M in 1993 Dollars = \$0/KW/Yr Each
 Variable O&M in 1993 Dollars = \$2.31/MWH
 Annual Escalation Rates:
 Plant Costs = 4.75%/Yr to 2004, 4.3%/Yr After 2005
 Fixed O&M = 3.15%/Yr to 2004, 3.5%/Yr After 2005
 Utility Discount Rate = 8.81%/Yr
 Economic Life of the Avoided Units = 30 Years
 K Factor = 1.5156

**Purchased Power Payments for Option 3 - Repower
Units 3&4
Using Value of Deferral Method**

Year	Total O&M Cost	Total Capital Cost	Total Cap & O&M Cost
1994	0	0	0
1995	0	0	0
1996	0	0	0
1997	0	0	0
1998	0	0	0
1999	0	0	0
2000	0	0	0
2001	0	0	0
2002	0	0	0
2003	0	0	0
2004	5,277,426	17,438,823	22,716,249
2005	10,924,272	36,377,385	47,301,657
2006	11,287,504	37,941,813	49,229,116
2007	11,662,847	39,573,102	51,235,948
2008	12,050,705	41,274,745	53,325,451
2009	12,451,498	43,049,559	55,501,058
2010	12,865,658	44,900,690	57,766,349
2011	13,293,632	46,831,420	60,125,052
2012	13,735,882	48,845,171	62,581,053
2013	14,192,885	50,945,514	65,138,398
2014	14,665,135	53,136,171	67,801,305
2015	15,153,142	55,421,026	70,574,168
2016	15,657,433	57,804,130	73,461,563
2017	16,178,553	60,289,708	76,468,260
2018	16,717,065	62,882,165	79,599,230
2019	17,273,651	65,586,098	82,859,650
2020	17,848,614	68,406,300	86,254,914
2021	18,442,873	71,347,771	89,790,645
2022	19,056,973	74,415,726	93,472,699
2023	19,691,678	77,615,602	97,307,179
2024	20,347,373	80,953,073	101,300,446
2025	21,025,069	84,434,055	105,459,123
2026	21,725,398	88,064,719	109,790,117
2027	22,449,119	91,851,602	114,300,621
2028	23,197,016	95,801,117	118,998,132
2029	23,969,897	99,920,565	123,890,461
2030	23,640,255	105,523,930	129,164,186
2031	24,384,924	110,114,221	134,499,145
2032	25,153,049	114,904,190	140,057,239
2033	25,945,370	119,902,522	145,847,892
2034	13,381,375	62,559,141	75,940,465

Assumptions for Polk County Combined Cycle Units

Year of the Averted Units - Unit 3 = 2004, Unit 4 = 2005

Averted Unit Size = 235 MW Each

Total Installed Plant in 1993 Dollars = \$558/KW Each

Fixed O&M in 1993 Dollars = \$0/KW/Yr Each

Variable O&M in 1993 Dollars = \$2.31/MWH

Annual Escalation Rates

Plant Cost = 4.35%/Yr to 2004, 4.3%/Yr After 2005

Fixed O&M = 3.15%/Yr to 2004, 3.5%/Yr After 2005

Utility Discount Rate = 8.81%/Yr

Economic Life of the Averted Units = 30 Years

K Factor = 1.5156

**Purchased Power Payments for Option 3
CC Units 1,2,3 &4
Using Value of Deferral Method**

Year	Total O&M Cost	Total Capital Cost	Total Cap & O&M Cost
2001	4,808,553	15,347,577	20,156,130
2002	9,920,046	32,030,393	41,950,438
2003	10,232,527	33,423,715	43,656,242
2004	15,832,278	52,316,469	68,148,747
2005	21,848,543	72,754,770	94,603,313
2006	22,575,007	75,883,225	98,458,232
2007	23,325,693	79,146,204	102,471,897
2008	24,101,411	82,549,491	106,650,901
2009	24,902,997	86,099,119	111,002,116
2010	25,731,317	89,801,381	115,532,698
2011	26,587,264	93,662,840	120,250,105
2012	27,471,764	97,690,342	125,162,106
2013	28,385,770	101,891,027	130,276,797
2014	29,330,270	106,272,341	135,602,611
2015	30,306,283	110,842,052	141,148,335
2016	31,314,865	115,608,260	146,923,126
2017	32,357,106	120,579,415	152,936,521
2018	33,434,130	125,764,330	159,198,460
2019	34,547,103	131,172,196	165,719,299
2020	35,697,227	136,812,601	172,509,828
2021	36,885,747	142,695,543	179,581,290
2022	38,113,947	148,831,451	186,945,398
2023	39,383,155	155,231,203	194,614,359
2024	40,694,746	161,906,145	202,600,891
2025	42,050,137	168,868,109	210,918,247
2026	43,450,796	176,129,438	219,580,234
2027	44,898,238	183,703,004	228,601,242
2028	46,394,031	191,602,233	237,996,264
2029	47,939,794	199,841,129	247,780,923
2030	47,280,512	211,047,860	258,328,372
2031	36,577,386	165,171,331	201,748,718
2032	25,153,049	114,904,190	140,057,239
2033	25,945,370	119,902,522	145,847,892
2034	13,381,325	62,559,141	75,940,465

Assumptions for Polk County Combined Cycle Units

Year of the Avoided Units - Unit 1 = 2001, Unit 2 = 2002

Unit 3 = 2004, Unit 4 = 2005

Avoided Unit Size = 235 MW Each

Total Installed Plant in 1993 Dollars = \$558/KW Each

Fixed O&M in 1993 Dollars = \$0/KW/Yr Each

Variable O&M in 1993 Dollars = \$2.31/MWH

Annual Escalation Rates :

Plant Costs = 4.35%/Yr to 2004, 4.3%/Yr After 2005

Fixed O&M = 3.15%/Yr to 2004, 3.5%/Yr After 2005

Utility Discount Rate = 8.81%/Yr

Economic Life of the Avoided Units = 30 Years

K Factor = 1.5156

ATTACHMENT VIII

PLANNING STUDIES

"WHAT IF GAS AVAILABILITY SCENARIOS"

Polk County Gas Issues

December 15, 1993
Polk Co CC heatrate revision

Base assumptions:

- Anclote on Sunshine gas (1/1996)
- Polk Co cc on Sunshine gas (11/98 and 11/99)
- Turner and Higgins repower on Sunshine gas (1/2000 and 1/2002)

I. Delay of pipeline to 11/1999

1.
 - Anclote converted but no gas until 11/1999.
 - Polk Co #1 on distillate until 11/1999.
 - Polk Co #2 on Sunshine gas as in the base
 - Turner and Higgins repower on Sunshine gas (1/2000 and 1/2002) as in the base.

Results:

- Polk Co #1 limited operation to 500 hrs when operated on distillate.
 - Incremental cost for burning distillate at Polk #1 is \$28 million (nominal) in 1999.
2. Revised Anclote gas conversion schedule

- Anclote converted in 1998 and 1999.
- Polk Co #1 on distillate until 11/1999.
- Polk Co #2 on Sunshine gas as in the base
- Turner and Higgins repower on Sunshine gas (1/2000 and 1/2002) as in the base.

Results:

- Polk Co #1 limited operation to 500 hrs when operated on distillate.
- Save \$213,000 (cumulative present worth in 1993\$) between 1995 and 1999 due to the revised maintenance schedule.

II. Cancellation of pipeline

Alternative 1 - Sign up with FGT today:

- Anclote on FGT gas (1/1996).
- Polk Co cc on FGT gas (11/98 and 11/99).
- Turner and Higgins repower on FGT gas (1/2000 and 1/2002).

Results:

- Cost \$33 million (cumulative present worth in 1993\$).

Alternative 2 - Polk Co cc on FGT, no Anclote gas conversion, CR fuel switching:

- . Anclote on LS oil.
- . Polk Co cc on FGT gas (11/98 and 11/99).
- . Turner and Higgins repower on FGT gas (1/2000 and 1/2002).
- . Fuel switching CR 1 & 2.

Results:

- . Cost \$2 million (cumulative present worth in 1993\$).

Alternative 3 - Polk Co cc on FGT, no Anclote gas conversion, no CR fuel switching:

- . Anclote on LS oil.
- . Polk Co cc on FGT gas (11/98 and 11/99).
- . Turner and Higgins repower on FGT gas (1/2000 and 1/2002).

Results:

- . Savings \$35 million (cumulative present worth in 1993\$).
- . 2001 SO₂ exceeds the limit.

Alternative 4 - Polk Co cc on 0.05%- sulfur oil, no Anclote gas conversion, CR fuel switching:

- . Anclote on LS oil.
- . Polk Co cc on 0.05% sulfur oil (11/98 and 11/99).
- . Turner and Higgins repower on 0.05% sulfur oil (1/2000 and 1/2002).
- . Fuel switching CR 1 & 2.

Results:

- . Cost \$131 million (cumulative present worth in 1993\$).

SPL GAS NOT AVAILABLE UNTIL NOVEMBER 1999

1

ANNUAL PRODUCTION COST COMPARISON & PRESENT WORTH

DELTA = CHANGE MINUS BASE

RUN DATE 12/13/93

..... PRODUCTION COST (\$)			... PRESENT WORTH VALUES ..		
YEAR	PM930481 BASE	PM930486 CHANGE	DELTA	P.F.	DOLLARS
1993	602,888,789	602,888,789	0	1.000	0
1994	710,853,326	710,853,326	0	.9190	0
1995	851,028,870	848,311,196	-2,717,674	.8446	-2,295,407
1996	966,322,166	941,625,721	-24,696,445	.7762	-19,170,260
1997	1,041,134,962	1,032,481,959	-8,653,003	.7134	-6,172,934
1998	1,137,333,193	1,142,288,780	4,955,587	.6556	3,249,010
1999	1,196,673,879	1,224,435,251	27,761,372	.6025	16,727,385
2000	1,277,870,363	1,277,870,363	0	.5538	0
2001	1,368,698,925	1,368,698,925	0	.5089	0
2002	1,448,864,403	1,448,864,403	0	.4677	0
2003	1,535,854,147	1,535,854,147	0	.4298	0

-24,389,591

TOTAL PRESENT WORTH OF THE DELTAS @ 8.81%

-7,662,206

SPL NOT AVAILABLE UNTIL NOV 1999 * OLD VS NEW RUN (*main schedule*) 1

ANNUAL PRODUCTION COST COMPARISON & PRESENT WORTH

DELTA = CHANGE MINUS BASE

RUN DATE 12/16/93

.....PRODUCTION COST (\$)			...PRESENT WORTH VALUES...		
YEAR	PM930486 BASE	PM930507 CHANGE	DELTA	P.F.	DOLLARS
1993	602,888,789	602,888,789	0	1.000	0
1994	710,853,326	710,853,326	0	.9190	0
1995	848,311,196	848,221,667	-89,529	.8446	-75,618
1996	941,625,721	941,633,542	7,821	.7762	6,071
1997	1,032,481,959	1,032,481,959	0	.7134	0
1998	1,142,288,780	1,143,108,154	819,374	.6556	537,203
1999	1,224,435,251	1,223,305,557	-1,129,694	.6025	-680,688
2000	1,277,870,363	0-1,277,870,363		.5538	-707,628,190
2001	1,368,698,925	0-1,368,698,925		.5089	-696,558,255
2002	1,448,864,403	0-1,448,864,403		.4677	-677,654,692
2003	1,535,854,147	0-1,535,854,147		.4298	-660,179,253

TOTAL PRESENT WORTH OF THE DELTAS @ 8.81% ~~-2,742,233,423~~
- 213,032

STRATEGIC BASE VS. ANCLOTE POLK REPOWER ON FGT GAS

1

ANNUAL PRODUCTION COST COMPARISON & PRESENT WORTH

DELTA = CHANGE MINUS BASE

RUN DATE 12/13/93

.....PRODUCTION COST (\$)..... ..PRESENT WORTH VALUES..

YEAR	PM930481 BASE	PM930482 CHANGE	DELTA	P.F.	DOLLARS
1993	602,888,789	602,888,789	0	1.000	0
1994	710,853,326	710,853,326	0	.9190	0
1995	851,028,870	851,215,348	186,478	.8446	157,503
1996	966,322,166	969,421,078	3,098,912	.7762	2,405,486
1997	1,041,134,962	1,044,745,289	3,610,327	.7134	2,575,558
1998	1,137,333,193	1,141,489,437	4,156,244	.6556	2,724,940
1999	1,196,673,879	1,202,014,886	5,341,007	.6025	3,218,180
2000	1,277,870,363	1,286,376,105	8,505,742	.5538	4,710,104
2001	1,368,698,925	1,378,979,959	10,281,034	.5089	5,232,224
2002	1,448,864,403	1,462,077,057	13,212,654	.4677	6,179,748
2003	1,535,854,147	1,550,309,384	14,455,237	.4298	6,213,512

TOTAL PRESENT WORTH OF THE DELTAS @ 8.81% 33,417,255

ANCLOTE ON LS * POLK AND REPOWER ON FGT

1

ANNUAL PRODUCTION COST COMPARISON & PRESENT WORTH

DELTA = CHANGE MINUS BASE

RUN DATE 12/13/93

.....PRODUCTION COST (\$)..... ..PRESENT WORTH VALUES..

YEAR	PM930481 BASE	PM930483 CHANGE	DELTA	P.F.	DOLLARS
1993	602,888,789	602,888,789	0	1.000	0
1994	710,853,326	710,853,326	0	.9190	0
1995	851,028,870	848,311,196	-2,717,674	.8446	-2,295,407
1996	966,322,166	941,625,721	-24,696,445	.7762	-19,170,260
1997	1,041,134,962	1,032,481,959	-8,653,003	.7134	-6,172,934
1998	1,137,333,193	1,139,560,899	2,227,706	.6556	1,460,541
1999	1,196,673,879	1,189,936,545	-6,737,334	.6025	-4,059,525
2000	1,277,870,363	1,274,378,685	-3,491,678	.5538	-1,933,537
2001	1,368,698,925	1,369,748,700	1,049,775	.5089	534,251
2002	1,448,864,403	1,445,328,762	-3,535,641	.4677	-1,653,670
2003	1,535,854,147	1,532,611,873	-3,242,274	.4298	-1,393,675

TOTAL PRESENT WORTH OF THE DELTAS @ 8.81% -34,684,216

ANCIOTE ON LS * POLK AND REPOWER ON .05 PERCENT OIL

1

ANNUAL PRODUCTION COST COMPARISON & PRESENT WORTH

DELTA = CHANGE MINUS BASE

RUN DATE 12/13/93

..... PRODUCTION COST (\$) PRESENT WORTH VALUES ..

YEAR	PM930481 BASE	PM930485 CHANGE	DELTA	P.F.	DOLLARS
			0	1.000	0
1993	602,888,789	602,888,789	0	.9190	0
1994	710,853,326	710,853,326	-2,717,674	.8446	-2,295,407
1995	851,028,870	848,311,196	-24,696,445	.7762	-19,170,260
1996	966,322,166	941,625,721	-8,653,003	.7134	-6,172,934
1997	1,041,134,962	1,032,481,959	3,546,678	.6556	2,325,293
1998	1,137,333,193	1,140,879,871	1,940,083	.6025	1,168,981
1999	1,196,673,879	1,198,613,962	54,572,770	.5538	30,219,991
2000	1,277,870,363	1,332,443,133	72,094,345	.5089	36,690,254
2001	1,368,698,925	1,440,793,270	92,762,599	.4677	43,386,400
2002	1,448,864,403	1,541,627,002	103,629,496	.4298	44,544,623
2003	1,535,854,147	1,639,483,643			

.....
TOTAL PRESENT WORTH OF THE DELTAS @ 8.81% 130,696,940

ANNUAL SYSTEM SO2 EMISSIONS



STRATEGIC BASE * PM-930460
*** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SO2 EMISSIONS (TONS) FROM FPC UNITS * PM-930460

1

IYR	SO2
1993	131,609
1994	132,717
1995	121,570
1996	114,208
1997	112,253
1998	117,178
1999	115,255
2000	107,030
2001	106,336
2002	104,816
2003	107,659

STRATEGIC BASE * PM-930460
*** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SO2 EMISSIONS (TONS) FROM TECO & UPS * PM-930460

2

IYR	UNITNAME	TOTALSO2	CREDIT	SO2
1993	TECO	331.41	0	331
1994	TECO	285.27	0	285
1995	TECO	210.80	0	211
1996	TECO	290.13	0	290
1997	TECO	348.61	0	349
1998	TECO	523.73	0	524
1999	TECO	444.08	0	444
2000	TECO	453.84	0	454
2001	TECO	567.15	0	567
2002	TECO	456.41	0	456
2003	TECO	503.57	0	504
1993	UPS PURC	0.00	8846	0
1994	UPS PURC	6665.74	8846	0
1995	UPS PURC	11247.82	8846	2,402
1996	UPS PURC	9617.85	8846	772
1997	UPS PURC	9204.45	8846	358
1998	UPS PURC	10416.46	8846	1,570
1999	UPS PURC	8885.98	8846	40
2000	UPS PURC	6945.19	8846	0
2001	UPS PURC	8050.94	8846	0
2002	UPS PURC	6408.08	8846	0
2003	UPS PURC	7003.63	8846	0

STRATEGIC BASE * PM-930460
 *** WITH FUEL SWITCHING AT BARTOW ***

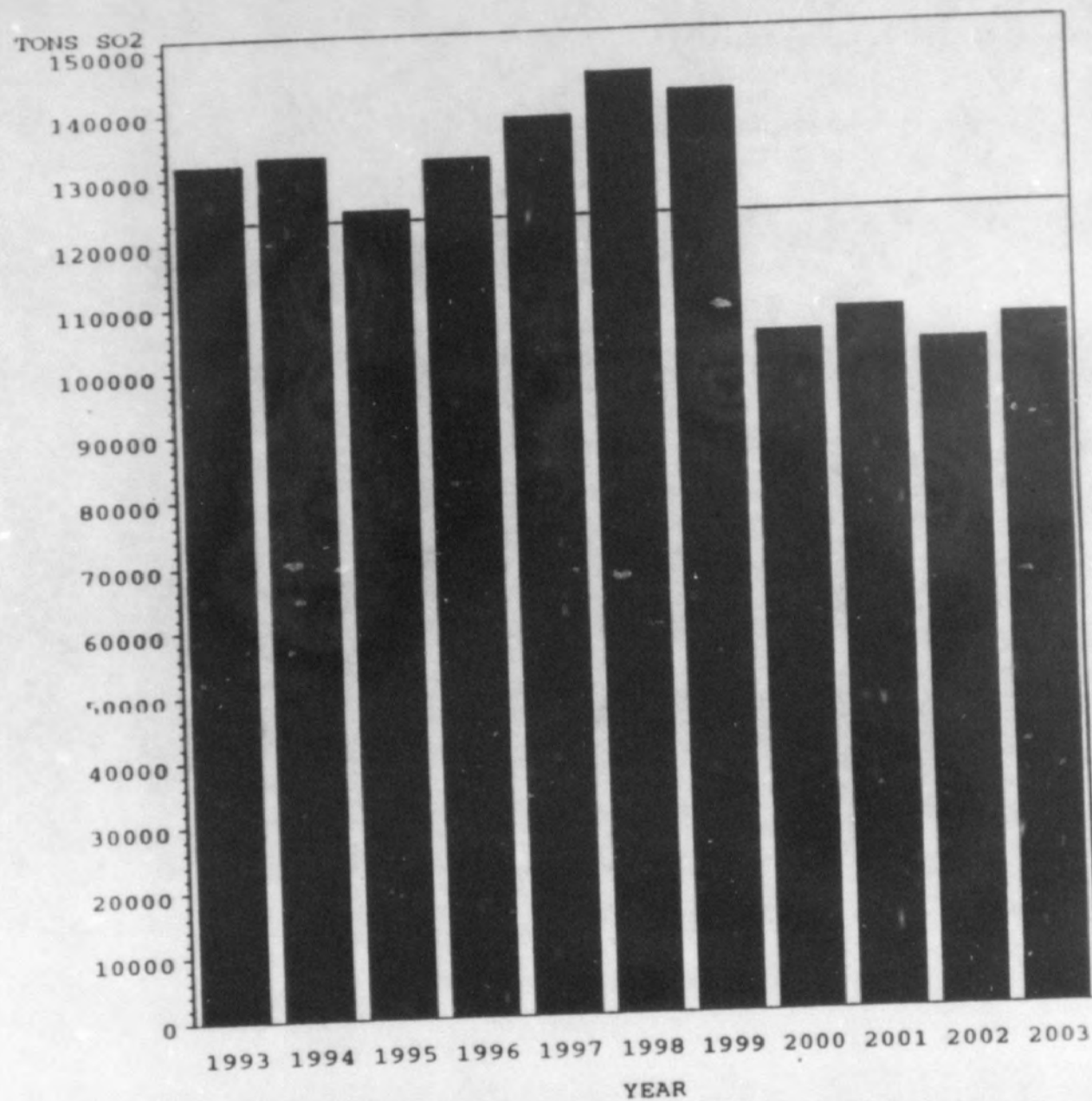
ANNUAL SYSTEM SO2 EMISSIONS (TONS) * PM-930460

3

IYR	SO2	SO2_PURC	SYS_SO2
1993	131,609	331	131,940
1994	132,717	285	133,002
1995	121,570	2,613	124,183
1996	114,208	1,062	115,270
1997	112,253	707	112,960
1998	117,178	2,094	119,272
1999	115,255	484	115,739
2000	107,050	454	107,504
2001	106,336	567	106,903
2002	104,816	456	105,273
2003	107,659	504	108,162

STRATEGIC BASE * PM-930460
 *** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SYSTEM SO2 EMISSIONS



ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930464
*** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

ANNUAL SO2 EMISSIONS (TONS) FROM FPC UNITS * PM-930464

1

IYR	SO2
1993	131,609
1994	132,717
1995	121,868
1996	129,109
1997	134,437
1998	139,029
1999	137,106
2000	101,828
2001	103,540
2002	99,890
2003	102,872

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930464
 *** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

ANNUAL SO2 EMISSIONS (TONS) FROM TECO & UPS * PM-930464

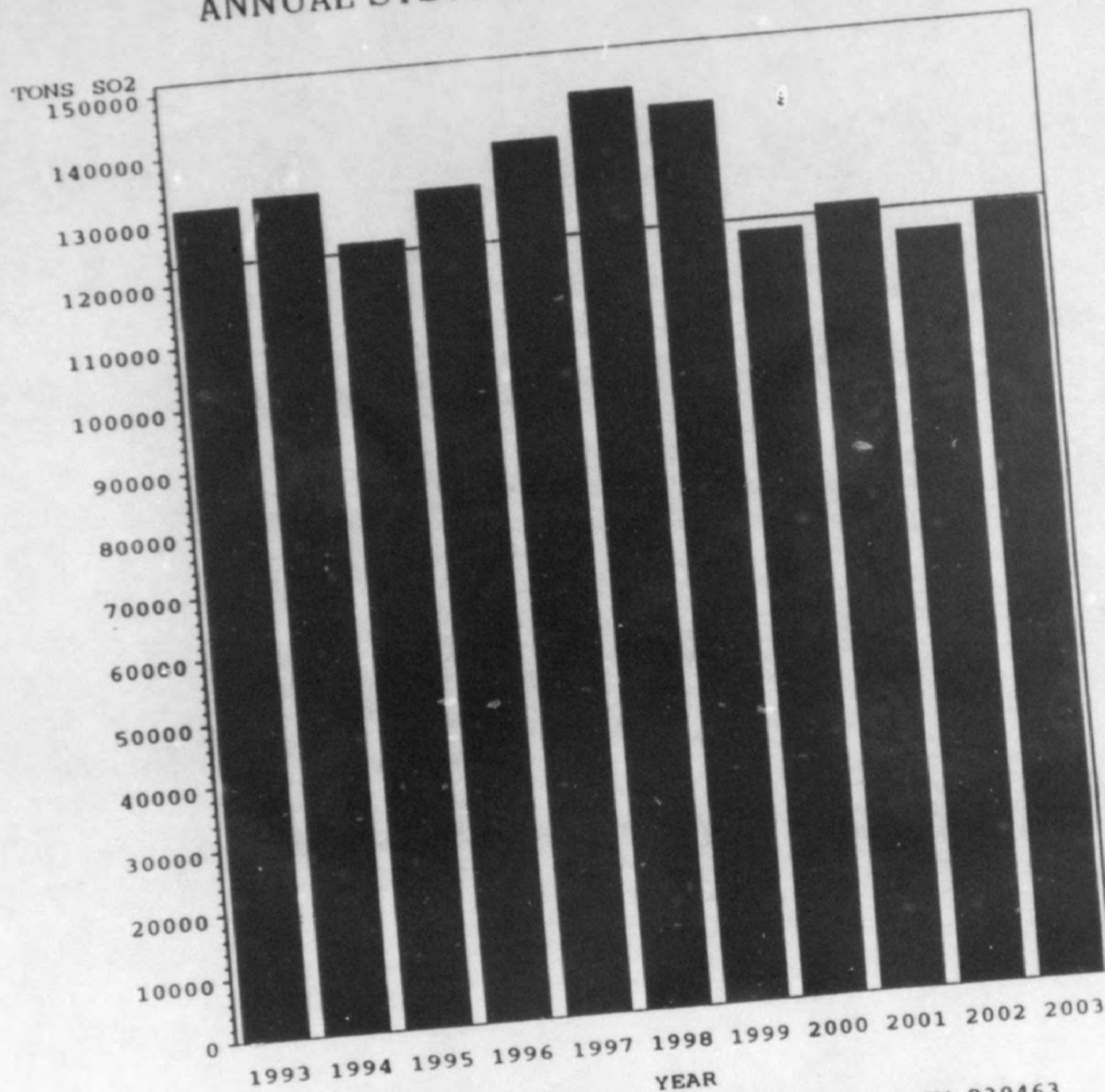
2

IYR	UNITNAME	TOTALSO2	CREDIT	SO2
1993	TECO	331.41	0	331
1994	TECO	285.27	0	285
1995	TECO	211.38	0	211
1996	TECO	455.96	0	456
1997	TECO	705.35	0	705
1998	TECO	985.99	0	986
1999	TECO	972.27	0	972
2000	TECO	930.28	0	930
2001	TECO	1113.08	0	1,113
2002	TECO	906.16	0	906
2003	TECO	916.56	0	917
1993	UPS PURC	0.00	8846	0
1994	UPS PURC	6665.74	8846	0
1995	UPS PURC	11290.64	8846	2,445
1996	UPS PURC	11408.73	8846	2,563
1997	UPS PURC	12059.10	8846	3,213
1998	UPS PURC	13825.28	8846	4,979
1999	UPS PURC	12554.87	8846	3,709
2000	UPS PURC	10270.19	8846	1,424
2001	UPS PURC	11717.13	8846	2,871
2002	UPS PURC	10398.41	8846	1,552
2003	UPS PURC	10900.13	8846	2,054

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930464
 *** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

IYR	SO2	SO2_PURC	SYS_SO2
1993	131,609	331	131,940
1994	132,717	285	133,002
1995	121,868	2,656	124,524
1996	129,109	3,019	132,128
1997	134,437	3,918	138,356
1998	139,029	5,965	144,994
1999	137,106	4,681	141,787
2000	101,828	2,354	104,182
2001	103,540	3,984	107,524
2002	99,890	2,459	102,348
2003	102,872	2,971	105,843

ANNUAL SYSTEM SO2 EMISSIONS



ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930463
 *** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SO2 EMISSIONS (TONS) FROM FPC UNITS * PM-930463
.....

1

IYR	SO2
1993	131,609
1994	132,717
1995	121,868
1996	129,109
1997	134,437
1998	139,029
1999	137,106
2000	118,654
2001	120,345
2002	116,688
2003	119,591

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930463
*** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SO2 EMISSIONS (TONS) FROM TECO & UPS * PM-930463

2

IYR	UNITNAME	TOTALSO2	CREDIT	SO2
			0	331
1993	TECO	331.41	0	285
1994	TECO	285.27	0	211
1995	TECO	211.38	0	456
1996	TECO	455.96	0	705
1997	TECO	705.35	0	986
1998	TECO	985.99	0	972
1999	TECO	972.27	0	930
2000	TECO	930.28	0	1,113
2001	TECO	1113.08	0	906
2002	TECO	906.16	0	917
2003	TECO	916.56	0	0
		0.00	8846	0
1993	UPS PURC	6665.74	8846	2,445
1994	UPS PURC	11290.64	8846	2,563
1995	UPS PURC	11408.73	8846	3,213
1996	UPS PURC	12059.10	8846	4,979
1997	UPS PURC	13825.28	8846	3,709
1998	UPS PURC	12554.87	8846	1,424
1999	UPS PURC	10270.13	8846	2,871
2000	UPS PURC	11717.13	8846	1,549
2001	UPS PURC	10395.17	8846	2,054
2002	UPS PURC	10900.02	8846	
2003	UPS PURC			

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930463
 *** WITH FUEL SWITCHING AT BARTOW ***

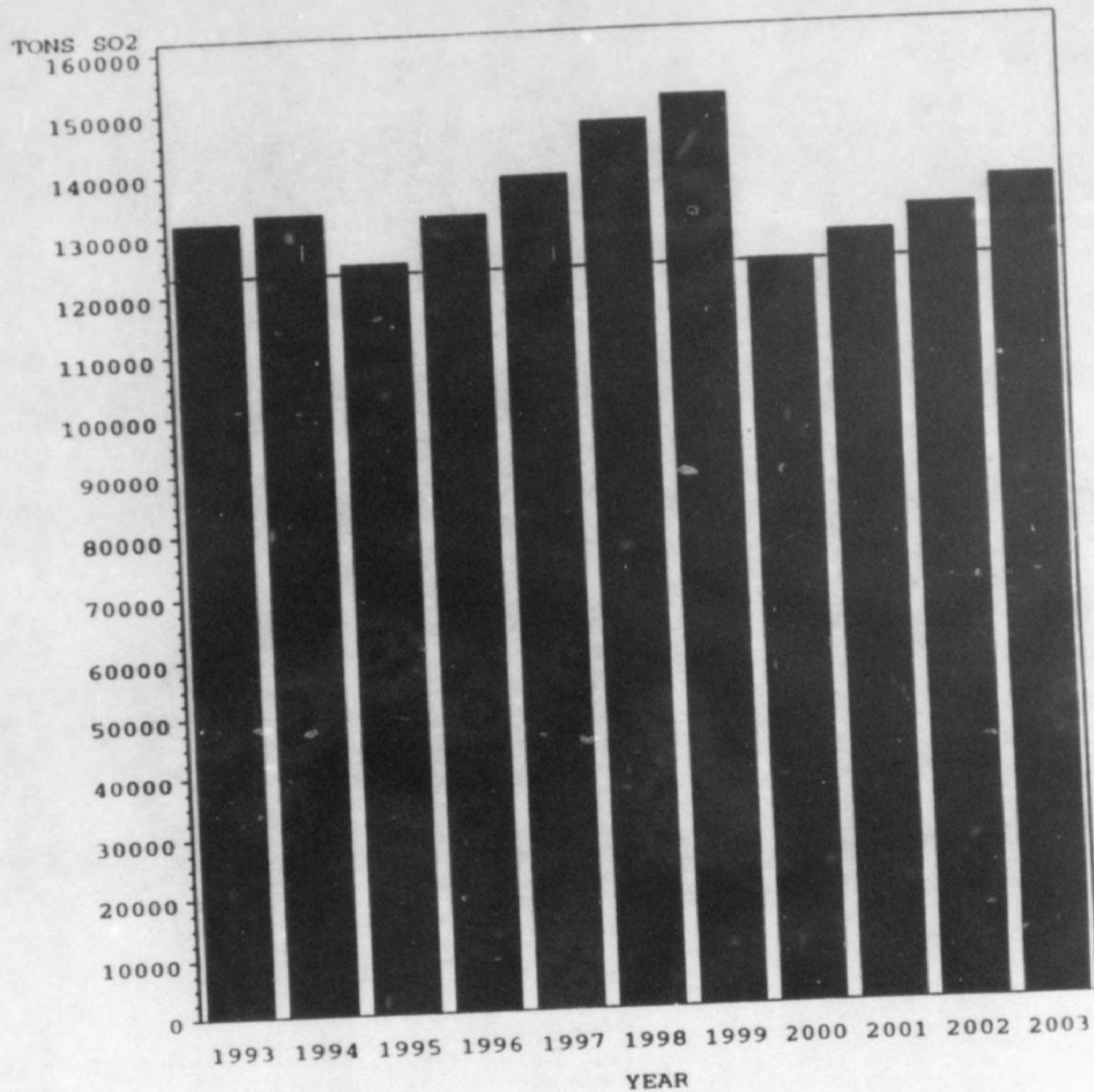
ANNUAL SYSTEM SO2 EMISSIONS (TONS) * PM-930463

3

IYR	SO2	SO2_PURC	SYS_SO2
1993	131,609	331	131,940
1994	132,717	285	133,002
1995	121,868	2,656	124,524
1996	129,109	3,019	132,128
1997	134,437	3,918	138,356
1998	139,029	5,965	144,994
1999	137,106	4,681	141,787
2000	118,654	2,354	121,008
2001	120,345	3,984	124,330
2002	116,688	2,455	119,144
2003	119,591	2,971	122,561

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON FGT * PM-930463
 *** WITH FUEL SWITCHING AT BARTOW ***

ANNUAL SYSTEM SO2 EMISSIONS



ANCHOTE ON L.S. OIL * POLK AND REPOWER ON .05% * PM 930465
*** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

ANNUAL SO2 EMISSIONS (TONS) FROM PPC UNITS * PM-930465

1

IYR	SO2
1993	131,609
1994	132,717
1995	121,868
1996	129,109
1997	134,437
1998	140,647
1999	144,812
2000	116,011
2001	119,091
2002	122,339
2003	126,151

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON .05% * PM-930465
*** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

IYR	UNITNAME	TOTALSO2	CREDIT	SO2
1993	TECO	331.41	0	331
1994	TECO	285.27	0	285
1995	TECO	211.38	0	211
1996	TECO	455.96	0	456
1997	TECO	705.35	0	705
1998	TECO	1025.29	0	1,025
1999	TECO	1181.90	0	1,182
2000	TECO	1669.38	0	1,669
2001	TECO	1820.83	0	1,821
2002	TECO	1898.12	0	1,898
2003	TECO	1973.22	0	1,973
1993	UPS PURC	0.00	8846	0
1994	UPS PURC	6665.74	8846	0
1995	UPS PURC	11290.64	8846	2,445
1996	UPS PURC	11408.73	8846	2,563
1997	UPS PURC	12059.10	8846	3,213
1998	UPS PURC	14086.51	8846	5,241
1999	UPS PURC	13484.80	8846	4,639
2000	UPS PURC	14316.71	8846	5,471
2001	UPS PURC	15386.46	8846	6,540
2002	UPS PURC	16065.33	8846	7,219
2003	UPS PURC	16473.94	8846	7,628

ANNUAL SYSTEM SO2 EMISSIONS (TONS) * PM-930465

3

IYR	SO2	SO2_PURC	SYS_SO2
1993	131,609	331	131,940
1994	132,717	285	133,002
1995	121,868	2,656	124,524
1996	129,109	3,019	132,128
1997	134,437	3,918	138,356
1998	140,647	6,266	146,912
1999	144,812	5,821	150,633
2000	116,011	7,140	123,151
2001	119,091	8,361	127,452
2002	122,339	9,117	131,456
2003	126,151	9,601	135,752

ANCLOTE ON L.S. OIL * POLK AND REPOWER ON .05% * PM-930465
 *** WITH FUEL SWITCHING AT BARTOW AND CRYSTAL 1-2 ***

ATTACHMENT IX

WORST CASE

REGULATORY COMPLIANCE COSTS

**FPC POLK COUNTY SITE
REGULATORY COMPLIANCE COSTS - OPERATIONS**

Condition	Page	Description	Initial Installed Cost	Expected Annual O&M Cost	Expected Duration	Total Expected O&M Cost	Worst Case Annual O&M Cost	Worst Case Duration	Total Worst Case O&M Costs	FTB	Comments
XIII C	1	Annual Compliance Tests	\$5,852,000*	\$150,000	40 years	\$6,000,000	\$3,167,500	40 years	\$126,700,000	< 0.1	Potential for worst case is believed to be low based on manufacturers' projections of equipment performance
XIII A 4 XIII D XIII E 1	2	Continuous Emission Monitors	\$400,000	\$180,000	40 years	\$7,200,000	\$180,000	40 years	\$7,200,000	1	
XV	3	Domestic Wastewater System		\$13,212	40 years	\$528,480	\$14,260	40 years	\$570,400	0.5	
XVI C	4	Drinking Water Facilities		\$43,578	40 years	\$1,743,120	\$45,586	40 years	\$1,823,440	0.5	
XVII H	5	Annual Dam Inspection	NA	\$15,000	40 years	\$600,000	\$15,000	40 years	\$600,000	< 0.1	
XVII G 2 XVIII A	6	Wastewater and Groundwater Monitoring	\$5,820	\$129,312	40 years	\$5,172,480	\$129,312	40 years	\$5,172,480	0.2	Negotiable after 4 quarters of groundwater monitoring
XXI B	7	Solid Waste Disposal Area		\$14,236	40 years	\$569,440	\$14,236	40 years	\$569,440	0.1	
XXII	8	Pollutant Emission Fees	NA	\$36,120	40 years	\$1,444,800	\$36,120	40 years	\$1,444,800	0	
XXI B 10 XXV E XXVI A XXX 17	9	Water Use/Conservation Report	\$10,000	\$76,000	40 years	\$3,040,000	\$76,000	40 years	\$3,040,000	1	
XXIV 12 XXV F 4	10	Erosion and Nuisance Control	NA	\$12,000	5 years	\$60,000	\$13,310	5 years	\$66,550	< 0.1	Carry over from construction, until vegetation is established
XXIV	11	Wetlands Reclamation	\$2,000,000	\$212,000	5 years	\$1,060,000	\$2,500,000	Multiple plantings	\$5,546,875	< 0.1	Carry over from construction, until vegetation is established
XXV F 7 XXX 16	12	Wildlife Habitat Management Plan	NA	\$ 26,000	10 years	\$260,000	\$26,000	35 years	\$910,000	< 0.1	Begins after vegetation is established
XXX 10	13	Hazardous Material Reporting	NA	\$400	40 years	\$16,000	\$30,000	40 years	\$493,000	< 0.1	Worst case assumes utilities lose current exemption
XXX 18	14	Ambient Air Monitoring	\$150,000*	\$150,000	10 years	\$1,500,000	\$200,000	40 years	\$8,000,000	0.3*	Negotiable, experts expect success in eliminating requirement
TOTALS						\$29,194,320 **			\$162,336,985 **		

* Based on worst case assumption

** In 1994 Dollars

01/26/94

FPC Polk County Site

REQUIREMENT: Annual Compliance Tests

CONDITION: XIII (pages 13-22)

AGENCY: DEP

SUMMARY:

Perform annual compliance tests on each combustion turbine with the fuels used for more than 400 hours in the preceding 12-month period (Condition XIII.C.1), and test fuel for sulfur content, fuel bound nitrogen and lower heating value (Condition XIII.C.2).

BASIS: Required by 17-297, FAC and 40 CFR 60.334

ANNUAL O&M COST: \$150,000

FTE'S REQUIRED: <0.1

SCHEDULE: On-going during the life of the units (assumed to be 40 years), annually from the date of the initial compliance test.

WORST CASE SCENARIO: The worst case scenario is failing the NO_x compliance test, resulting in a requirement to install and operate a selective catalytic reduction (SCR) system.

COST OF WORST CASE SCENARIO: Incremental increased annual O&M cost of \$3,167,500 for operation of SCR.

APPLICABILITY OF REQUIREMENT:

Annual compliance testing applies to new sources whether on a large site or "postage stamp" and regardless of whether approval is received under the Power Plant Siting Act (PPSA) or through standard permitting.

RECOMMENDED ACTION:

Contract language with equipment supplier should protect against worst case scenario and shift responsibility to vendor should the worst case occur.

FPC Polk County Site

REQUIREMENT: Continuous Emission Monitors

CONDITION: XIII (pages 13-22)

AGENCY: DEP

SUMMARY:

Operate a continuous emission monitor (CEM) on each combined cycle unit for NO_x emissions and submit quarterly excess emissions and monitoring system performance reports to DEP (Condition XIII.D), and monitor fuel use for both natural gas and fuel oil (Conditions XIII.A.4 and XIII.E.1).

BASIS: Required by 40 CFR Part 75 of the Clean Air Act Amendment

ANNUAL O&M COST:

\$100,000 - CEMs
60,000 - RATA testing
<u>20,000</u> - Calibration of fuel flow meters
\$180,000

FTE'S REQUIRED: 1

SCHEDULE: On-going during operation of the combined cycle unit (assumed to be 40 years).

WORST CASE SCENARIO: None

COST OF WORST CASE SCENARIO: None

APPLICABILITY OF REQUIREMENT:

CEM requirement applies to new sources whether on a large site or "postage stamp" and regardless of whether approval is received under the PPSA or through standard permitting. There are exemptions from installing CEMs for any facility which is less than 25 MW and burns ultra clean fuel (<0.05 % sulfur). There are other exemptions from the Acid Rain Program for cogenerators with a maximum potential output of less than 25 MW, and qualifying facilities of 1 or more units with a total installed net output capacity not exceeding 130% of planned output capacity.

RECOMMENDED ACTION: None

FPC Polk County Site

REQUIREMENT: Domestic Wastewater System

CONDITION: XV (pages 24-27)

AGENCY: DEP

SUMMARY:

Operation of an on-site domestic wastewater system requires a certified plant operator (Condition XV.6); sampling and monthly reporting of wastewater system discharges (Condition XV.7); annual analysis of sludge (Condition XV.8); and miscellaneous compliance activities, such as providing a weatherproof location for an on-site log book (Condition XV.13) and maintaining lift station alarms in operating condition (Condition XV.14). Connection to a municipal sewage treatment plant is allowed by the conditions of certification.

BASIS: Required by 17-600 thru 17-610, FAC

ANNUAL O&M COST:

\$	208 - Annual sludge analysis
	4,200 - Certified plant operator
	600 - Calibration of flow meter
	1,785 - Chemicals (sodium hypochlorite)
	5,579 - Sludge disposal costs
	<u>840</u> - Annual wastewater analysis
	\$13,212*

FTE'S REQUIRED: 0.5 (administrative functions by several personnel)

SCHEDULE: On-going during operation of the facilities (assumed to be 40 years).

WORST CASE SCENARIO: Regulatory requirements will become more stringent and costly over time, due to new federal rules.

COST OF WORST CASE SCENARIO: \$14,260 (assumes sludge and wastewater analysis costs double)

APPLICABILITY OF REQUIREMENT:

Requirements are standard for any facility planning an on-site treatment system, whether a large site or "postage stamp" site. The decision of on-site treatment versus treatment by a municipal system is dependent upon the location of the site (i.e., pipeline costs and water use fees may equal or exceed capital and operating expenditures for an on-site facility).

RECOMMENDED ACTION:

Evaluate the cost effectiveness of on-site domestic wastewater system as compared with connecting to either the City of Fort Meade or Bartow municipal system.

* Cost information based on Crystal River South sewage treatment plant facilities.

FPC Polk County Site

REQUIREMENT: Drinking Water Facilities

CONDITION: XVI (pages 28-35)

AGENCY: DEP

SUMMARY:

Operation of on-site drinking water facilities requires a certified plant operator (Condition XVI.C.6); sampling and monthly reporting of water quality (Conditions XVI.C.8 and 9); and miscellaneous compliance activities, such as periodic reading of the water meter (Condition XVI.C.7). Connection to a municipal water supply system is allowed by the conditions of certification.

BASIS: Required by 17-550 thru 17-555, FAC

ANNUAL O&M COST:

- \$ 4,160 - Certified plant operator
- 34,680 - FTE loaded salary
- 300 - Annual water analyses
- 1,200 - Calibration of flow meter
- 1,530 - Chemicals (lime, sodium hypochlorite, etc.)
- 1,708 - Annual average of 9 year compliance analyses

\$43,578*

FTE'S REQUIRED: 0.5 (administrative functions by several personnel)

SCHEDULE: On-going during operation of the facilities (assumed to be 40 years).

WORST CASE SCENARIO: Regulatory requirements will become more stringent and costly over time, due to reauthorization of Safe Drinking Water Act and changes in State Water Policy.

COST OF WORST CASE SCENARIO: \$45,586 (assumes water analysis costs double)

APPLICABILITY OF REQUIREMENT:

Requirements are standard for any facility planning an on-site water supply system, whether a large site or "postage stamp" site. The decision of on-site water supply versus water from a municipal system is dependent upon the location of the site (i.e., pipeline costs and water use charges may equal or exceed capital and operating expenditures for an on-site water supply system).

RECOMMENDED ACTION:

Evaluate the cost effectiveness of on-site drinking water facilities as compared with connecting to either the City of Fort Meade or Bartow municipal system.

* Cost information based on Crystal River South drinking water facilities.

FPC Polk County Site

REQUIREMENT: Annual Dam Inspection

CONDITION: XVII.H (page 38)

AGENCY: DEP

SUMMARY:

Conduct an annual dam inspection by a Florida P.E. experienced in dam construction and maintenance, and submit report to DEP.

BASIS: Required by 17-672, FAC

ANNUAL O&M COST: \$15,000 (based on 15 miles of dam at \$1,000/mile)
Additional expenditures are required for dam maintenance. FPL budgets approximately \$100,000/mile for mowing and dam repair/maintenance.

FTE'S REQUIRED: <0.1

SCHEDULE: On-going during the operation of the site (assumed to be 40 years).

WORST CASE SCENARIO: None

COST OF WORST CASE SCENARIO: None

OTHER POTENTIAL ISSUES:

Cooling pond dams represent a potential risk to public safety. Results of the annual inspection may note suggested repairs or needed maintenance. Failure to respond to such findings in a timely manner poses a liability and could be used as evidence against FPC in the event of a dam failure.

APPLICABILITY OF REQUIREMENT:

Dam inspections of cooling ponds structures are normally required. A "postage stamp" or a project planned without a cooling pond would not have dam inspections, but would have alternate requirements and expenses. For example, alternate cooling methods such as cooling towers, dry condensers or once thru cooling would bear additional regulatory requirements and costs.

RECOMMENDED ACTION:

Appropriate emphasis should be placed on the maintenance, patrolling and upkeep of the dams on-site. Operations personnel should inspect the dams on a daily basis.

REQUIREMENT: Wastewater and Groundwater Monitoring

CONDITION: XVII (pages 36-39) and XVIII (pages 40-45) **AGENCY:** DEP

SUMMARY:

The Groundwater Monitoring Plan consists of:

- 1) Sampling 3 wells every 5 years for ambient concentrations of primary and secondary drinking water parameters, etc. . . (Condition XVIII.A.7).
- 2) Sampling of cooling pond water every 5 years (Condition XVIII.A.8).
- 3) Quarterly sampling of 9 wells (Condition XVIII.A.9).

Condition XVII.G.2 requires a clay permeability test for the brine pond liner.

BASIS: Required by 17-520 thru 17-522, FAC.

ANNUAL O&M COST:

\$ 13,872	- FTE loaded salary for sample collecting and reporting
97,800	- Annual cost for quarterly sampling of 9 wells
15,000	- Clay permeability test for brine pond (5 year duration)
1,980	- Average annual cost of ambient well sampling
<u>660</u>	- Average annual cost of cooling pond sampling
\$129,312*	

FTE'S REQUIRED: 0.2

SCHEDULE:

System must be constructed at least 30 days prior to completion of construction of the cooling pond, brine pond and solid waste disposal area (Condition XVIII.A.2), and continue for the life of the facility (assumed to be 40 years). The clay permeability test for the brine pond has a 5 year duration.

WORST CASE SCENARIO:

Although Condition XVIII.A.10 allows FPC to request a reduction in sampling frequency or specific parameters, the worst case scenario assumes FPC is not allowed to reduce the frequency or parameters. The clay permeability testing runs for the life of the facility (assumed to be 40 years) in the worst case scenario.

COST OF WORST CASE SCENARIO: No reduction in annual O&M cost.

APPLICABILITY OF REQUIREMENT:

Monitoring is required for projects that have a discharge or potential discharge to groundwater. The costs for the program would be dependent upon the number of wells and parameters. The clay permeability testing is due to the zero discharge design of the Polk County Site and would not apply to a "postage stamp" site.

RECOMMENDED ACTION:

At the completion of 4 quarters of monitoring well sampling, request a reduction in the monitoring program pursuant to Condition XVIII.A.10.

* Costs based on analysis by contract laboratories. Use of FPC's Central Lab could result in \$22,000 annual savings.

FPC Polk County Site

REQUIREMENT: Solid Waste Disposal Area

CONDITION: XXI (pages 47-50)

AGENCY: DEP

SUMMARY:

FPC must comply with the following:

- 1) Record quantities of leachate (Condition XXI.B.10)
- 2) Sample leachate from the solid waste disposal area annually (Condition XXI.B.14)
- 3) Perform TCLP analyses on materials which may be deemed to be hazardous waste (Condition XXI.B.12)

BASIS: Required by Resource Conservation Recovery Act (RCRA), 17-701, and 17-730, FAC if disposal occurs on-site.

ANNUAL O&M COST: \$ 6,936 - FTE loaded salary for sample collection and reporting
3,300 - Annual analysis of leachate
4,000 - TCLP analyses
\$14,236

FTE'S REQUIRED: 0.1

SCHEDULE: Requirements are for the life of the facility (assumed to be 40 years).

WORST CASE SCENARIO: None

COST OF WORST CASE SCENARIO: None

OTHER POTENTIAL ISSUES:

Regulations concerning disposal of combustion by-products could change as a result of revised industrial waste studies required by 17-701, FAC.

APPLICABILITY OF REQUIREMENT:

Requirements reflect FPC's planning for future coal gasification facilities at the Polk County Site. Any facility proposing on-site disposal of waste must comply with 17-701, FAC. A natural gas-fired generating unit by itself probably would not propose on-site disposal. Some level of TCLP testing would occur at any power plant site if disposal is occurring.

RECOMMENDED ACTION:

Ensure that any suggested revisions to 17-701, FAC recognize the suitability and equivalency of clay liners such as are present at the Polk County Site for combustion by-product disposal. When coal gasification slag is produced on-site, specific efforts should be made to market the material, thereby avoiding waste disposal.

FPC Polk County Site

REQUIREMENT: Pollutant Emission Fees

CONDITION: XXII (page 51)

AGENCY: DEP

SUMMARY:

FPC must submit the appropriate annual pollutant emission fees and information (Condition XXII.B).

BASIS: Required by Clean Air Act Amendment Title V, 17-103, 17-210, and 17-213, FAC

ANNUAL O&M COST: \$36,120*

FTE'S REQUIRED: 0

SCHEDULE: Payment is due annually in the March following the first year of operation, and continues for the life of the facility (assumed to be 40 years).

WORST CASE SCENARIO: Annual fees will increase over time.

COST OF WORST CASE SCENARIO: Unknown

APPLICABILITY OF REQUIREMENT:

Requirement applies to emission sources whether on a large site or "postage stamp" and regardless of whether approval is under the PPSA or through standard permitting.

RECOMMENDED ACTION: None

* Based on maximum potential emissions at \$35/ton.

FPC Polk County Site

REQUIREMENT: Water Use/Conservation Report

CONDITION: See below

AGENCY: See below

SUMMARY:

To track and report the use of water, FPC is required to do the following:

- 1) Maintain a continuous recording rain gauge and report monthly (Condition XXI.B.10 (page 48), DEP; and Condition XXVI.A.19 (pages 73-74), SWFWMD)
- 2) Provide water crop data (Condition XXV.E (page 63), DEP)
- 3) Meter and report monthly on groundwater withdrawals (Condition XXVI.A.16 (page 72), SWFWMD)
- 4) Quarterly report on groundwater use (Condition XXX.17 (page 103), Polk County)
- 5) Annual report on water conservation (Condition XXX.17 (page 103), Polk County)

BASIS: FPC agreed to do this in the Conditions of Certification. Not required by federal or state law.

ANNUAL O&M COST: \$ 1,000 - Reporting
75,000 - Water management coordination
\$76,000

FTE'S REQUIRED: 1

SCHEDULE: On-going during operation of the facility (assumed to be 40 years).

WORST CASE SCENARIO: None

COST OF WORST CASE SCENARIO: None

OTHER POTENTIAL ISSUES:

With the major concern about water supplies in Florida, records on water conservation and water cropping will be increasingly important in the future.

APPLICABILITY OF REQUIREMENT:

Metering and reporting of groundwater use is required by SWFWMD water use permits for any project using groundwater, whether on a large site or "postage stamp" site. The annual water conservation report was required by Polk County and typically would not be required of a "postage stamp" site.

RECOMMENDED ACTION: None

FPC Polk County Site

REQUIREMENT: Exotic and Nuisance Control

CONDITION: XXIV.I.2 (page 58) and XXV.F.4 (page 65)

AGENCY: DEP

SUMMARY:

Exotic and nuisance species shall be controlled and limited to:

- 1) 10 percent or less in wetland areas in N-9B and N-13 (Condition XXIV.I.2)
- 2) 25 percent or less in upland areas in SA-10, N-9B and N-13 (Condition XXV.F.4)

BASIS: FPC agreed to do this in the Conditions of Certification. Not required by federal or state law.

ANNUAL O&M COST: \$13,310 First year costs (herbicide and labor) for 844 acres
11,620 Annually for second thru fifth years
\$12,000* Annual average for 5 year effort

FTE'S REQUIRED: <0.1

SCHEDULE: Continues until planted vegetation is established, estimated to be at least 5 years depending upon vegetation type.

WORST CASE SCENARIO:

The worst case scenario is that the vegetation does not become established, and the exotic and nuisance control continues for the life of the facility at the higher herbicide application rate required for the first year.

COST OF WORST CASE SCENARIO: \$13,310 per year until vegetation is established

APPLICABILITY OF REQUIREMENT:

A smaller "postage stamp" site would have fewer acres of wetlands, if any, which require mitigation. Consequently, this requirement would be reduced or non-existent.

RECOMMENDED ACTION:

Contract language should shift responsibility for successful eradication of exotic and nuisance species to the contractor applying herbicide.

* Cost estimate based on use of contract labor.

FPC Polk County Site

REQUIREMENT: Wetlands Mitigation

CONDITION: XXIV (pages 56-60)

AGENCY: DEP

SUMMARY:

To ensure the successful establishment of wetlands, FPC is required to:

- 1) Retain a qualified biological consultant (Condition XXIV.D)
- 2) Replant to obtain specified success criteria (Conditions XXIV.E thru J)
- 3) Submit an annual statistical report (Condition XXIV.K)
- 4) Submit a plan for corrective action if vegetation is not trending toward success (Condition XXIV.K)

BASIS: FPC agreed to do this in the Conditions of Certification. Not required by federal or state law.

ANNUAL O&M COST: \$ 8,000 - Biological consultant (Assuming 8 days/year @ \$1,000/day)
 \$200,000 - Replanting (Based on 10% of planting costs or \$900/acre)
 4,000 - Annual report
 \$212,000

FTE'S REQUIRED: <0.1

SCHEDULE: Until vegetation is established, estimated to be between 3 to 5 years.

WORST CASE SCENARIO:

The worst case scenario is most of the planted vegetation fails, and the area must be redesigned and replanted.

COST OF WORST CASE SCENARIO: \$2,500,000 for full redesign and first replanting at \$9,000/acre
 \$1,875,000 for second replanting (75% failure)
 \$ 937,500 for third replanting (50% failure)
 \$ 234,375 for fourth replanting (25% failure)

APPLICABILITY OF REQUIREMENT:

Mitigation is typically required for construction projects affecting wetlands. Success criteria, monitoring and reporting are standard requirements. A smaller "postage stamp" site would have fewer acres of wetlands, if any, which require mitigation. Consequently, this requirement would be reduced or non-existent.

RECOMMENDED ACTION:

Contract language should include a guarantee on successful establishment of vegetation or a grower's maintenance agreement.

FPC Polk County Site

REQUIREMENT: Wildlife Habitat Management Plan

CONDITION: XXV.F.7 (page 65)

AGENCY: DEP

CONDITION: XXX.16 (page 102-103)

AGENCY: Polk County

SUMMARY:

Establish and implement a Wildlife Habitat Management Plan for the site buffer area, in consultation with the DEP, FL Game & Fresh Water Fish Commission (FGFWFC), U.S. Fish & Wildlife Service (FWS), and Polk County. The Plan has been approved by FGFWFC and FWS, and is under discussion with the DEP.

BASIS: FPC agreed to do this in the Polk County Conditional Use Permit.

ANNUAL O&M COST: \$11,000 - Exotic and nuisance control
5,000 - Annual inspections and summary reports for 10 years
10,000 - Annual average for thinning of vegetation once every 3 years
\$26,000 (assumes the use of contract labor)

FTE'S REQUIRED: <0.1

SCHEDULE:

Requirement does not begin until wetland mitigation is established (see page 11). 10 year duration.

WORST CASE SCENARIO:

The worst case scenario is DEP or Polk County does not agree to a 10 year limit on the duration of the Plan, or requires additional or more frequent management practices.

COST OF WORST CASE SCENARIO: \$26,000 annually for 35 years (assumes 5 years for establishment of vegetation)

APPLICABILITY OF REQUIREMENT:

Requirement resulted from concern raised by a local environmentalist at Polk County land use public hearing. In all likelihood, such a plan would not be required of a "postage stamp" site.

RECOMMENDED ACTION:

Work with DEP and Polk County to finalize specifics of the Wildlife Habitat Management Plan.

FPC Polk County Site

REQUIREMENT: Hazardous Material Reporting

CONDITION: XXX.10 (page 100)

AGENCY: Polk County

SUMMARY:

Report annually on the storage and use of hazardous materials on-site.

BASIS: Required by Emergency Planning & Community Right-to-Know Act (EPCRA).

ANNUAL O&M COST: \$400

FTE'S REQUIRED: <0.1

SCHEDULE: On-going during the life of the facility (assumed to be 40 years).

WORST CASE SCENARIO: Utilities lose current exemption from TRI reporting.

COST OF WORST CASE SCENARIO:
\$30,000 for first year of reporting
\$17,000 for subsequent years

APPLICABILITY OF REQUIREMENT:

EPCRA reporting is currently required of any facility which stores and uses certain quantities of hazardous materials on-site. Cogenerators are presently required to do TRI reporting. Under the worst case scenario, which assumes a change in regulatory requirements, FPC would be required to do TRI reporting at all facilities which report under EPCRA, including the Polk County Site. The EPA Secretary has announced her intention to require utilities to do TRI reporting.

RECOMMENDED ACTION:

Reduce the planned use of hazardous chemicals to minimize reporting requirements.

FPC Polk County Site

REQUIREMENT: Ambient Air Monitoring

CONDITION: XXX.18 (page 103)

AGENCY: Polk County

SUMMARY:

FPC shall provide up to two ambient air monitoring stations, if not provided by the DEP Title V air monitoring network or other means.

BASIS: FPC agreed to do this in the Polk County Conditional Use Permit. Not required by federal or state law.

ANNUAL O&M COST: \$150,000 (assuming inability to negotiate out of this requirement)

FTE'S REQUIRED: 0.3

SCHEDULE: Concurrent with the operation of the first combined cycle unit, and continue for 10 years.

WORST CASE SCENARIO:

Although the condition language suggests that the monitoring requirements and number of stations are negotiable and may be met by DEP's network or other means, the worst case scenario is that FPC is required to install two monitoring stations and maintain them for 40 years. A worst case assumption was made as to the monitoring parameters.

COST OF WORST CASE SCENARIO: \$200,000 annually for 40 years

APPLICABILITY OF REQUIREMENT:

Some projects are required to have ambient air monitoring stations under the conditions of their air permits. This requirement is often a reflection of fuel and technology choices.

RECOMMENDED ACTION:

Work closely with DEP and Polk County to ensure the appropriate siting of ambient air monitoring stations through the Title V network or by other means. Failing in this effort, FPC should prepare a strong rationale and defense for not providing ambient air monitoring stations. If FPC is unable to avoid installing air monitoring stations, the monitored pollutants should be limited, and duration of monitoring should be restricted. If no project-related impacts are observed, the requirement should cease.

LEVELIZED

WORST CASE

O & M COSTS

Worst Case Operating & Maintenance Cost Estimate

POLK COUNTY SITE						
	First 470 MW		Second 470 MW		Full 940 MW	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
COMPLIANCE						
CEMS						
(responsible party: FPC)	\$180,000	0.38	\$180,000	0.38	\$360,000	0.38
Annual Air Compliance Tests						
(responsible party: FPC)	\$150,000	0.32	\$150,000	0.32	\$300,000	0.32
Air Pollution Fees						
(responsible party: FPC)	\$38,120	0.08	\$38,120	0.08	\$72,240	0.08
Annual Dam Inspection						
(responsible party: FPC)	\$15,000	0.03	\$0	0.00	\$15,000	0.02
Waste Stream Characterization						
(responsible party: FPC)	\$1,880	0.00	\$0	0.00	\$1,880	0.00
Ground Water Monitoring						
(responsible party: FPC)	\$100,440	0.21	\$0	0.00	\$100,440	0.11
Reclamation/ Reporting						
(responsible party: FPC)	\$814,011	1.31	\$0	0.00	\$814,011	0.85
Hazardous Materials Reporting						
(responsible party: FPC)	\$17,325	0.04	\$0	0.00	\$17,325	0.02
Water Use Monitoring/Reporting						
(responsible party: FPC)	\$18,000	0.03	\$0	0.00	\$18,000	0.02
Field Permeability Testing/SWDA						
(responsible party: FPC)	\$22,300	0.05	\$0	0.00	\$22,300	0.02
Potable Water Testing						
(responsible party: FPC)	\$8,178	0.02	\$0	0.00	\$8,178	0.01
NPDES Monitoring/Reporting						
(responsible party: Ebasco)	\$0	0.00	\$0	0.00	\$0	0.00
IWW Monitoring						
(responsible party: Ebasco)	\$317	0.00	\$834	0.00	\$851	0.00
MSSW Monitoring						
(responsible party: Ebasco)	\$0	0.00	\$0	0.00	\$0	0.00
Domestic Wastewater System						
(responsible party: FPC)	\$4,818	0.01	\$0	0.00	\$4,818	0.00
Ambient Air Monitoring						
(responsible party: FPC)	\$200,000	0.43	\$0	0.00	\$200,000	0.21
COMPLIANCE TOTAL	\$1,385,885	2.91	\$368,754	0.78	\$1,732,739	1.84

WORST CASE OPERATING & MAINTENANCE COST ESTIMATE

POLK COUNTY SITE						
	First 470 MW		Second 470 MW		Full 940 MW	
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
SITE MANAGEMENT						
Security	\$75,000	0.16	\$0	0.00	\$75,000	0.08
(responsible party: FPC)						
Cooling Pond/Cooling Tower	\$0	0.00	\$0	0.00	\$0	0.00
(responsible party: Ebasco)						
Brine Pond	\$20,000	0.04	\$0	0.00	\$20,000	0.02
(responsible party: FPC)						
SWDA	\$28,838	0.06	\$0	0.00	\$28,838	0.03
(responsible party: FPC)						
Plant Island (SA-11, SA-12 & SA-13)	\$88,520	0.15	\$0	0.00	\$88,520	0.07
(responsible party: Ebasco)						
Water Crop System	\$40,000	0.09	\$0	0.00	\$40,000	0.04
(responsible party: FPC)						
Dam Maintenance	\$138,438	0.29	\$0	0.00	\$138,438	0.15
(responsible party: Ebasco)						
Mowing	\$118,395	0.25	\$0	0.00	\$118,395	0.12
(responsible party: Ebasco)						
Nuisance and Exotics Control	\$5,514	0.01	\$0	0.00	\$5,514	0.01
(responsible party: FPC)						
Dam Surveillance	\$33,040	0.07	\$0	0.00	\$33,040	0.04
(responsible party: Ebasco)						
SITE MANAGEMENT TOTAL	\$523,840	1.11	\$0	0.00	\$523,840	0.56

WUNST CASE OPERATING & MAINTENANCE COST ESTIMATE

POWER PLANT

Fuel

(responsible party: FPC)

Power system - Boilers

(responsible party: Ebasco)

Power system - Steam Turbines

(responsible party: Ebasco)

Power system - Gas Turbines

(responsible party: FPC)

Power system - Auxiliary Equipment

Electric Switchgear & Controls

(responsible party: Ebasco)

Power system - Annual Outage

(responsible party: Ebasco)

Power system - Purchasing

(responsible party: FPC)

Condenser Cooling System

(responsible party: Ebasco)

Condenser cooling Backpressure

Penalty (responsible party: Ebasco)

Condenser cooling Auxiliary Power

(responsible party: Ebasco)

Cooling Water Supply

(responsible party: Ebasco)

Process Water Supply

(responsible party: Ebasco)

Process Wastewater Treatment

(responsible party: Ebasco)

Process Waste Disposal

(responsible party: FPC)

Potable Water Supply - Onsite

(responsible party: FPC)

Sanitary Wastewater Disposal

Onsite (responsible party: Ebasco)

POLK COUNTY SITE					
First 470 MW		Second 470 MW		Full 940 MW	
\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr	\$/kw
\$50,024,084	108.43	\$50,024,084	108.43	\$100,048,169	108.43
\$210,785	0.45	\$210,785	0.45	\$421,570	0.45
\$272,511	0.58	\$272,511	0.58	\$545,022	0.58
\$1,000,000	2.13	\$1,000,000	2.13	\$2,000,000	2.13
\$220,000	0.47	\$220,000	0.47	\$440,000	0.47
\$304,200	0.85	\$304,200	0.85	\$608,400	0.85
\$53,587	0.11	\$53,587	0.11	\$107,184	0.11
\$28,821	0.08	\$28,821	0.08	\$58,242	0.08
0 MW	0.00	0 MW	0.00	0 MW	0.00
0 MW	0.00	0 MW	0.00	0 MW	0.00
\$471,000	1.00	\$78,500	0.17	\$548,500	0.58
\$114,387	0.24	\$114,387	0.24	\$228,775	0.24
\$0	0.00	\$0	0.00	\$0	0.00
\$13,872	0.03	\$0	0.00	\$13,872	0.01
\$37,410	0.08	\$0	0.00	\$37,410	0.04
\$7,964	0.02	\$0	0.00	\$7,964	0.01

WORST CASE OPERATING & MAINTENANCE COST ESTIMATE

POLK COUNTY SITE					
	First 470 MW		Second 470 MW		Full 940 MW
	\$/Yr	\$/kw	\$/Yr	\$/kw	\$/Yr \$/kw
Solid Waste Disposal (responsible party: Ebasco)	\$40,950	0.00	\$40,950	0.00	\$81,900 0.00
Property Taxes (responsible party: Ebasco)	\$3,070,000	8.45	\$3,010,000	8.11	\$7,780,000 8.28
POWER PLANT TOTAL	\$6,748,200	14.35	\$6,134,552	13.05	\$12,880,848 13.70

Operating & Maintenance Total	\$8,638,123	18.37	\$8,501,308	13.83	\$15,137,428	18.10
\$ / Megawatt Hour **	\$2.88		\$2.02		\$2.30	
O & M Total including Fuel	\$58,880,217	110.48	\$58,525,400	107.21	\$115,185,817	108.83
\$ / Megawatt Hour **	\$18.27		\$17.80		\$17.83	

** megawatt hours - 470 MW * 8700 * 70CF - 3,211,416 MWHr's or 1,603,216 MWHr's for 220 MW unit

FLORIDA POWER CORPORATION
 POLK COUNTY SITE
 Worst Case Operating & Maintenance Cost Estimate
 Assumptions - Impacted Items Only

Page 1 of 2

Compliance	
	Polk County Site
Continuous Emission Monitoring System	Per Condition XIII, (page 2 of ESD report).
Annual Air Compliance	Per Condition XIII, (page 1 of ESD report), No SCR anticipated, rely on manufacturer to guarantee, competing units will have same requirements.
Air Pollution Fees	Per Condition XXII.B, (page 8 of ESD report).
Annual Dam Inspection	Per Condition XVII.H, (page 5 of ESD report), 3rd party inspection by Florida P.E.
Waste Stream Characterization	Per Condition XV, (page 3 of ESD report), used annual wastewater analysis only, refer to Domestic Wastewater System (Compliance) and Sanitary Wastewater Disposal (Plant) for balance of costs.
Groundwater Monitoring	Per Conditions XVII and XVIII, (page 6 of ESD report), includes quarterly well sampling, well & pond sampling, refer to Field Permeability (Compliance) and Process Waste Disposal (Plant) for balance of costs.
Reclamation / Reporting	Conditions XXIV, XXV.F.7, and XXX.16 have been leveled for life of plant, (pages 11 and 12 of ESD report). Includes wetland mitigation in multiple plantings and wildlife habitat management plans.
Hazardous Materials Program	Per Condition XXX.10, (page 13 of ESD report), Includes training, drills, record keeping, updates, reporting and program coordination for Emgcy Resp and SPCC Plans. Chemicals application include fuel oil and water treatment.
Water Use Monitoring & Reporting	Monthly, quarterly, and annual read & reporting for DEP, SWFWMD, and Polk County, (page 9 of ESD report), includes reporting and .2FTE, Balance of costs included under Site Management responsibilities.

Field Permeability Testing / SWDA	Condition XVII.6.2 has been levelized for life of plant plus Condition XXI, (pages 6 and 7 of ESD report), includes clay permeability test and SWDA leachate analysis with .1FTE salary .
Potable Water Testing	Per Condition XVI.C, (page 4 of ESD report), includes certified operator, annual water analysis, and 9 yr. compl. analysis, refer to Potable Water Supply (Plant) for balance of costs.
NPDES Monitoring & Reporting	Not required due to Zero Discharge site design.
IWW Monitoring	Required for metal cleaning waste.
MSSW Monitoring	Not required due to Zero Discharge site design.
Domestic Wastewater System	Per Condition XV, (page 3 of ESD report), includes annual sludge analysis and certified plant operator, refer to Waste Stream Characterization (Compliance) and Sanitary Wastewater Disposal (Plant) for balance of costs.
Ambient Air Monitoring	Per Condition XXX.18, (page 14 of ESD report).

Site Management

Nuisance & Exotics	Conditions XXIV.I.2 and XXV.F.4 have been levelized for the life of plant, (page 10 of ESD report).
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ATTACHMENT X

FINANCIAL ASSESSMENT

**FLORIDA POWER CORPORATION
POLK COUNTY GENERATING UNITS
BUY VERSUS BUILD CONSIDERATIONS**

- * Assuming FPC can build as cheaply as it can purchase, ratepayer should be neutral.
- * The above statement presupposes FPC can pass along surcharge for additional equity issued to support purchased power imputed debt.
- * Under this neutral scenario, purchased power however adds no value to shareholders, as expense is directly passed to ratepayers via fuel adjustment clause.
- * Absent additional new generation assets, FPC ratebase will gradually diminish, thereby reducing operating revenues and net income.
- * As generation assets shrink, FPC moves in direction of becoming merely transmission and distribution entity.
- * Barring any new generation capability at Progress Energy to offset reduced FPC generation, attractiveness to capital markets (relative to peer electric utilities) should lessen considerably due to falling revenues and net income.
- * Consequently the cost of raising new debt and equity capital should also materially increase as investors move to utilities with greater growth prospects.

**Treasury Department
February 17, 1994**

FLORIDA POWER CORPORATION
POLK COUNTY GENERATING UNITS
ECONOMIC ANALYSIS
(\$ IN THOUSANDS)

Option 1: Proceed with units 1 through 4 as currently planned:

Assumptions:

MW per unit 235

Per unit cost (1993\$)

1	633
2	633
3	487
4	487

Economic life (years) 40

Capital structure

Debt	45.00%	8.00%
Equity	55.00%	19.54%

	Project Cost				Equity Reqmt.	Revenue Reqmt.	Debt Reqmt.	Revenue Reqmt.	Total Revenue Reqmt.	Cumulative	Net Income	Cumulative
	Unit 1	Unit 2	Unit 3	Unit 4								
1999	148,755				81,815	15,983	66,940	5,355	21,339	21,339	9,819	9,819
2000	145,036	148,755			161,585	31,567	132,206	10,576	42,144	63,482	19,392	29,210
2001	141,317	145,036			157,494	30,768	128,859	10,309	41,077	104,559	18,901	48,111
2002	137,598	141,317			153,404	29,969	125,512	10,041	40,010	144,569	18,410	66,521
2003	133,880	137,598			149,313	29,170	122,165	9,773	38,943	183,512	17,919	84,440
2004	130,161	133,880	114,445		208,167	40,668	170,318	13,625	54,293	237,805	24,982	109,422
2005	126,442	130,161	111,584	114,445	265,447	51,858	217,184	17,375	69,233	307,038	31,856	141,279
2006	122,723	126,442	108,723	111,584	258,209	50,444	211,262	16,901	67,345	374,382	30,988	172,266
2007	119,004	122,723	105,862	108,723	250,971	49,030	205,340	16,427	65,457	439,839	30,119	202,385
2008	115,285	119,004	103,001	105,862	243,733	47,616	199,418	15,953	63,569	503,409	29,250	231,635
2009	111,566	115,285	100,139	103,001	236,495	46,202	193,496	15,480	61,681	565,090	28,382	260,017
2010	107,847	111,566	97,278	100,139	229,257	44,788	187,574	15,006	59,794	624,884	27,513	287,530
2011	104,129	107,847	94,417	97,278	222,019	43,374	181,652	14,532	57,906	682,790	26,644	314,175
2012	100,410	104,129	91,556	94,417	214,781	41,960	175,730	14,058	56,018	738,808	25,776	339,951

2013	96,691	100,410	88,695	91,556	377,351														
2014	92,972	96,691	85,834	88,695	364,191	207,543	40,546	169,808	13,585	54,130	792,938	24,907	364,858						
2015	89,253	92,972	82,973	85,834	351,031	200,305	39,132	163,886	13,111	52,243	845,181	24,039	388,896						
2016	85,534	89,253	80,112	82,973	337,871	193,067	37,718	157,964	12,637	50,355	895,535	23,170	412,066						
2017	81,815	85,534	77,250	80,112	324,711	185,829	36,304	152,042	12,163	48,467	944,002	22,301	434,368						
2018	78,096	81,815	74,389	77,250	311,551	178,591	34,890	146,120	11,690	46,579	990,582	21,433	455,800						
2019	74,378	78,096	71,528	74,389	294,391	171,353	33,476	140,198	11,216	44,691	1,035,273	20,564	476,364						
2020	70,659	74,378	68,667	71,528	285,231	164,115	32,062	134,276	10,742	42,804	1,078,077	19,695	496,060						
2021	66,940	70,659	65,806	68,667	272,071	156,877	30,648	128,354	10,268	40,916	1,118,993	18,827	514,887						
2022	63,221	66,940	62,945	65,806	258,911	149,639	29,234	122,432	9,795	39,028	1,158,021	17,958	532,845						
2023	59,502	63,221	60,084	62,945	245,751	142,401	27,820	116,510	9,321	37,140	1,195,161	17,090	549,934						
2024	55,783	59,502	57,223	60,084	232,591	135,163	26,406	110,588	8,847	35,253	1,230,414	16,221	566,155						
2025	52,064	55,783	54,361	57,223	219,431	127,925	24,991	104,666	8,373	33,365	1,263,778	15,352	581,508						
2026	48,345	52,064	51,500	54,361	206,271	120,687	23,577	98,744	7,900	31,477	1,295,255	14,484	595,991						
2027	44,627	48,345	48,639	51,500	193,111	113,449	22,163	92,822	7,426	29,589	1,324,844	13,615	609,606						
2028	40,908	44,627	45,778	48,639	179,951	106,211	20,749	86,900	6,952	27,701	1,352,546	12,746	622,353						
2029	37,189	40,908	42,917	45,778	166,791	98,973	19,335	80,978	6,478	25,814	1,378,360	11,878	634,230						
						91,735	17,921	75,056	6,004	23,926	1,402,285	11,009	645,239						

**FLORIDA POWER CORPORATION
POLK COUNTY GENERATING UNITS
ECONOMIC ANALYSIS
(\$ IN THOUSANDS)**

Option 3: Proceed with units 1 and 2; 3 and 4 on smaller sites:

Assumptions:

MW per unit 235

Per unit cost (1993\$)

1	622
2	622
3	558
4	558

Economic life (years) 40

Capital structure

Debt	45.00%	8.00%
Equity	55.00%	19.54%

	Project Cost					Equity Reqmt.	Revenue Reqmt.	Debt Reqmt.	Revenue Reqmt.	Total Revenue Reqmt.	Cumulative	Net Income	Cumulative
	Unit 1	Unit 2	Unit 3	Unit 4	Total								
1999					0								
2000					0	0	0	0	0	0	0	0	0
2001	146,170				146,170	0	0	0	0	0	0	0	0
2002	142,516	146,170			288,686	80,394	15,706	65,777	5,262	20,968	20,968	9,648	9,648
2003	138,862	142,516			281,377	158,777	31,019	129,909	10,393	41,411	62,379	19,055	28,703
2004	135,207	138,862	131,130		405,199	154,757	30,233	126,620	10,130	40,363	102,742	18,572	47,275
2005	131,553	135,207	127,852	131,130	525,742	222,859	43,538	182,339	14,587	58,125	160,867	26,745	74,021
2006	127,899	131,553	124,574	127,852	511,877	289,158	56,490	236,584	18,927	75,417	236,284	34,702	108,722
2007	124,245	127,899	121,295	124,574	498,012	281,532	55,000	230,345	18,428	73,428	309,712	33,787	142,509
2008	120,590	124,245	118,017	121,295	484,147	273,907	53,510	224,105	17,928	71,439	381,151	32,871	175,380
2009	116,936	120,590	114,739	118,017	470,282	266,281	52,021	217,866	17,429	69,450	450,601	31,956	207,337
2010	113,282	116,936	111,461	114,739	456,417	258,655	50,531	211,627	16,930	67,461	518,062	31,041	238,378
2011	109,628	113,282	108,182	111,461	442,552	251,029	49,041	205,388	16,431	65,472	583,534	30,126	268,504
2012	105,973	109,628	104,904	108,182	428,687	243,404	47,551	199,148	15,932	63,483	647,017	29,211	297,715
						235,778	46,062	192,909	15,433	61,494	708,511	28,296	326,010

2013	102,319	105,973	101,626	104,904	414,822	228,152	44,572	186,670	14,934	59,505	768,017	27,380	353,391
2014	98,665	102,319	98,348	101,626	400,957	220,526	43,082	180,431	14,434	57,517	825,533	26,465	379,856
2015	95,011	98,665	95,069	98,348	387,092	212,901	41,592	174,191	13,935	55,528	881,061	25,550	405,406
2016	91,356	95,011	91,791	95,069	373,227	205,275	40,103	167,952	13,436	53,539	934,600	24,635	430,041
2017	87,702	91,356	88,513	91,791	359,362	197,649	38,613	161,713	12,937	51,550	986,149	23,720	453,761
2018	84,048	87,702	85,235	88,513	345,497	190,023	37,123	155,474	12,438	49,561	1,035,710	22,805	476,566
2019	80,394	84,048	81,956	85,235	331,632	182,398	35,633	149,234	11,939	47,572	1,083,282	21,889	498,455
2020	76,739	80,394	78,678	81,956	317,767	174,772	34,143	142,995	11,440	45,583	1,128,865	20,974	519,430
2021	73,085	76,739	75,400	78,678	303,902	167,146	32,654	136,756	10,940	43,594	1,172,460	20,059	539,489
2022	69,431	73,085	72,122	75,400	290,037	159,520	31,164	130,517	10,441	41,605	1,214,065	19,144	558,633
2023	65,777	69,431	68,843	72,122	276,172	151,895	29,674	124,277	9,942	39,616	1,253,681	18,229	576,862
2024	62,122	65,777	65,565	68,843	262,307	144,269	28,184	118,038	9,443	37,627	1,291,309	17,314	594,175
2025	58,468	62,122	62,287	65,565	248,442	136,643	26,695	111,799	8,944	35,639	1,326,947	16,399	610,574
2026	54,814	58,468	59,009	62,287	234,577	129,017	25,205	105,560	8,445	33,650	1,360,597	15,483	626,057
2027	51,160	54,814	55,730	59,009	220,712	121,392	23,715	99,320	7,946	31,661	1,392,258	14,568	640,625
2028	47,505	51,160	52,452	55,730	206,847	113,766	22,225	93,081	7,446	29,672	1,421,929	13,653	654,278
2029	43,851	47,505	49,174	52,452	192,982	106,140	20,736	86,842	6,947	27,683	1,449,612	12,738	667,016

Treasury Department
February 17, 1994

RATE

IMPACT

COMPARISON OF ANNUAL SYSTEM REVENUE REQUIREMENTS
EXTENDED PLAN - INCLUDING C.C. 3 & 4 IMPACTS

POLK COUNTY SITE STUDY

YEAR	DELTA SYSTEM REVENUE REQUIREMENT			SYSTEM ENERGY REQUIREMENT (GWH)	DELTA SYSTEM REVENUE REQUIREMENT		
	DELTA 1-1 (\$000)	DELTA 2-1 (\$000)	DELTA 3-1 (\$000)		OPTION 1 (\$/MWH)	OPTION 2 (\$/MWH)	OPTION 3 (\$/MWH)
1994	0	0	0	31,660	0.00	0.00	0.00
1995	0	0	0	33,240	0.00	0.00	0.00
1996	0	0	0	34,806	0.00	0.00	0.00
1997	0	0	0	36,278	0.00	0.00	0.00
1998	0	0	0	37,472	0.00	0.00	0.00
1999	0	(2,577)	(11,328)	38,634	0.00	-0.07	-0.29
2000	0	(5,153)	(877)	39,707	0.00	-0.13	-0.02
2001	0	(4,965)	9,694	40,799	0.00	-0.12	0.24
2002	0	(4,765)	(1,703)	41,890	0.00	-0.11	-0.04
2003	0	(4,588)	(1,658)	42,978	0.00	-0.11	-0.04
2004	0	(1,358)	1,447	44,084	0.00	-0.03	0.03
2005	0	7,568	10,262	45,262	0.00	0.17	0.23
2006	0	7,333	9,926	45,262	0.00	0.16	0.22
2007	0	7,134	9,610	45,262	0.00	0.16	0.21
2008	0	6,956	9,302	45,262	0.00	0.15	0.21
2009	0	6,808	9,025	45,262	0.00	0.15	0.20
2010	0	6,676	8,762	45,262	0.00	0.15	0.19
2011	0	6,549	8,506	45,262	0.00	0.14	0.19
2012	0	6,409	8,237	45,262	0.00	0.14	0.18
2013	0	6,286	7,985	45,262	0.00	0.14	0.18
2014	0	6,144	7,627	45,262	0.00	0.14	0.17
2015	0	5,964	7,270	45,262	0.00	0.13	0.16
2016	0	5,767	7,133	45,262	0.00	0.13	0.16
2017	0	(1,062)	357	45,262	0.00	-0.02	0.01
2018	0	5,138	6,494	45,262	0.00	0.11	0.14
2019	0	5,100	6,391	45,262	0.00	0.11	0.14
2020	0	4,939	6,166	45,262	0.00	0.11	0.14
2021	0	5,046	6,209	45,262	0.00	0.11	0.14
2022	0	5,053	6,153	45,262	0.00	0.11	0.14
2023	0	5,250	6,286	45,262	0.00	0.12	0.14
2024	0	5,287	6,259	45,262	0.00	0.12	0.14
2025	0	5,248	6,156	45,262	0.00	0.12	0.14
2026	0	4,773	5,617	45,262	0.00	0.11	0.12
2027	0	4,905	5,685	45,262	0.00	0.11	0.13
2028	0	4,895	5,611	45,262	0.00	0.11	0.12
2029	0	5,424	7,813	45,262	0.00	0.12	0.17
2030	0	5,839	5,474	45,262	0.00	0.13	0.12
2031	0	5,719	3,118	45,262	0.00	0.13	0.07
2032	0	5,633	5,633	45,262	0.00	0.12	0.12

17-Feb-94
02:18 PM

An attempt was made to reflect the differential cost of Option 2 and 3 versus the base Option 1 and the impact on rates. This was accomplished by reflecting the differential revenue requirements on a \$/MWH basis. The delta system revenue costs (\$) were divided by system energy requirements (MWH) to obtain a rate impact on a \$/MWH basis. For example, the data above shows that Option 2 is projected to yield rates that are .07 \$/MWH lower than Option 1 in 1999. However, the data reflects that rates under Option 2 would be .17 \$/MWH more expensive than Option 1 by 2005.

EXHIBIT C

DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJORS

DESCRIPTION: FLORIDA POWER CORPORTION POLK COUNTY
SITE 1996 ESTIMATED COSTS

**FLORIDA POWER CORPORATION
POLK COUNTY GENERATION PROJECT
SUMMARY OF ESTIMATED COSTS - POWER BLOCK 1**
(Escalated Dollars in Thousands)

Line	Project Category	1991 Need Hearing	Year End Forecast			May-96 Current Forecast
			1993	1994 *	1995	
1	Site Selection	\$ 1,669	\$ 1,669	\$ 1,669	\$ 1,669	\$ 1,669
2	Site Certification	15,206	26,174	19,076	18,969	18,969
3	Land and Site Development	60,200	62,105	65,640	65,428	62,687
4	Subtotal Site Development	77,075	89,948	86,385	86,066	83,325
5	Plant	337,266	250,766	268,331	162,763	158,228
6	AFUDC & GAC	78,628	55,820	60,916	43,571	39,424
7	Subtotal Generation Plant	492,969	396,534	415,632	292,400	280,977
8	Transmission and Subs. Plant	12,000	12,000	12,000	12,000	12,910
9	Total Project Cost	\$ 504,969	\$ 408,534	\$ 427,632	\$ 304,400	\$ 293,887
10	MW	470	470	700	507	507
11	\$ / KW Total Project Cost	\$ 1,074	\$ 869	\$ 611	\$ 600	\$ 580
12	\$ / KW Total Project w/o AFUDC	\$ 907	\$ 750	\$ 524	\$ 514	\$ 502
13	\$ / KW-Generation Plant Only	\$ 1,049	\$ 844	\$ 594	\$ 577	\$ 554
14	\$ / KW-Generation Plant w/o AFUDC	\$ 882	\$ 725	\$ 507	\$ 491	\$ 476

* 1994 data reflects Westinghouse 'G' technology units which were considered for an interim period of time.

6/3/96 11:00

ES-Financial & Cost Management/nlh
G:\EXCEL\POLK\COMPDEPO.XLS



EXHIBIT D

DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJORS

DESCRIPTION: FLORIDA POWER CORPORATION POLK COUNTY
SITE COMBINED CYCLE GENERATION STUDY
(JULY 1994)

Polk County Combined Cycle Generation Study

Author: R. W. Lehnhoff 4033
Department: Generation Planning
Date: July 8, 1994



Background Information

During 1991, FPC submitted a petition to the FPSC to build four 235MW combined cycle (CC) units at Polk County. The first unit was planned to be built in 1998 with subsequent units to be built each year until 2001. The size and type of the units were determined using screening and economic evaluation processes. Also, load growth and reserve margin considerations influenced the unit size and construction timing.

In their response, the FPSC granted the petition for the first two 235MW units. The PSC also concluded that the need for the two remaining units should be considered at some future time due to various uncertainties.

Purpose

The purpose of the study was determine the most economic design configuration for the first 470MW of generation at Polk County. Two alternatives were considered in the evaluation process and they are listed as follows.

1. One 455MW two-on-one CC unit, which consists of two combustion turbines (CT) exhausting through separate heat recovery steam generators (HRSG) that collectively provide steam to one steam turbine (ST), fueled by natural gas to be in-service by August 1998.

2. Two 226MW one-on-one CC units, each unit comprised of one CT with a HRSG that provides steam to a ST, fueled by natural gas, with one unit to be in-service by August 1998 and the other unit to be in-service by November 1999.

Note that 200 to 250MW of generation capacity is needed by August 1998 to help serve the summer peak demand.

Data and Analysis Scenarios

The data used for this study was provided by Mack & Veatch and was based on the GE 7FA unit only (see Appendix A). This unit is representative of a typical unit available in the market in both size and cost. Also, GE has more data available for their units than other vendors. A summary of the data categories are listed as follows.

1. Alternative Costs

- A. Capital costs for each unit configuration.

- B. Spending profiles for each unit configuration.

- C. Fixed O&M costs for each unit configuration.
 - D. Variable O&M costs for each unit configuration.
 - E. Capital costs for each substation configuration.
2. Unit Characteristics
- A. Unit capacities for summer and winter for each configuration.
 - B. Unit heat rates for summer and winter for each configuration.
 - C. Unit forced outage rates for each configuration.
 - D. Unit maintenance requirements for each configuration.

Three operating scenarios for the two-on-one CC configuration were considered in this study and are listed as follows. The three scenarios encompass an operating range that emulate the operation of the dual one-on-one configuration.

- 1. The plant operates with the two CTs and the ST in unison at all times as a single unit.
- 2. The plant operates with either one or two CTs plus the ST on line at any given time, with the minimum plant output determined by only one CT on line at its minimum output.
- 3. The plant operates with one or two CTs plus the ST on line at any given time, with the minimum plant output determined by only one CT on line at its maximum output.

For each of the operating scenarios, the unit capacity states and heat rates were modified. The unit costs and spending profiles remained the same. The results obtained from each of the scenarios were compared to the dual one-on-one configuration results to determine the most economic choice.

Study Results

The study results indicate that the two-on-one CC unit is the most economic configuration (see Appendix B). The reasons for this result are listed as follows. Note that all cost figures are shown in 1993 dollars.

- 1. The net output of the plant was slightly higher (2MW).
- 2. The net heat rate over the operating range of the plant is

slightly better (7-51Btu/KWh).

3. The fixed O&M costs are slightly less (\$0.15/KW/year).
4. The variable O&M costs are slightly less (\$0.07/MWh).
5. The substation costs were substantially less (\$1,900,000).
6. The total plant cost was substantially less (\$16,500,000).

As a consequence of the plant costs and operating characteristics, the two-on-one configuration will save between \$4,000,000 and \$15,000,000 over the 30-year life of the plant depending on how the plant is operated during that period.

Additional Comparisons

The dual one-on-one configuration appears to have three advantages in comparison to the two-on-one configuration. These advantages are outlined as follows.

1. The plant reliability is slightly better since two STs exist, instead of one. However, the benefit does not have any significant impact on the company reliability.
2. The flexibility of plant operations is slightly better during maintenance since each unit is isolated. However, this benefit is minimal for the overall plant operation.
3. The plant is more fuel efficient at net outputs in the range of 100 to 150MW. This impact may or may not be significant depending on the system generation needs. However, at this time, the impact is anticipated to be minimal.

Therefore, since the advantages have minimal impact, the most economic design is the two-on-one configuration.

Additional Considerations

After reviewing the initial study results, another consideration appears to be a viable economic alternative. The alternative is to defer the second CT of the two-on-one CC plant until November 1999. This alternative was evaluated by modifying the unit characteristics and spending profiles to model the three operating scenarios that were previously evaluated. The results were compared to the dual one-on-one configuration results to determine the effect.

The study results show that this alternative would provide an

additional savings in the range of \$1,000,000 to \$2,000,000 (see Appendix C). However, this alternative may not be feasible from a construction aspect or may require special considerations by management that could yield it invalid.

Recommendations for Future Analysis

The first recommendation is to perform additional studies to obtain in-depth information about the plant operation. The additional studies would include using some in-house software packages that were not used in this study. The results would provide valuable insights into the plant operation and needs. Also, sensitivity studies should be performed to determine the major factors and their range of values that are driving the cost analysis. These studies should be completed before bids are received for the plant.

The second recommendation is to investigate the feasibility of deferring the second CT in the two-on-one configuration for one year. Additional in-depth studies should be performed to determine the system impact and cost savings for this alternative. Also, additional information about construction considerations and limitations needs to be obtained.

The final recommendation is to evaluate each viable construction bid using the in-depth models. These evaluations could be used as input to the decision as to which plant design is the most cost-effective for FPC.

Summary

The study results indicate that the two-on-one CC plant is the most cost-effective design for Polk County. Based on the data supplied for the study and conversations with Black and Veatch, a very high probability, above 80%, exists that additional studies will conclude that the two-on-one design will always be the most cost-effective under all possible scenarios.

Additional in-depth studies should be performed to determine plant operation and to explore the feasibility of phased construction for the two-on-one CC plant. Also, the models created from the studies could be used to evaluate the construction bids for the plant.

06/22/94

18:26

B&V PWR DIV

NO. 546

P001



BLACK & VEATCH

14001 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-7111
FAX NUMBER: 913-339-2934 913-339-2936 913-339-2939

FACSIMILE TRANSMISSION

TO: RANDY LEHNHOFF
COMPANY: FPC
FAX NUMBER: 813-866-4994
TELEPHONE NUMBER:
FROM: STEVE CLARK *smc*
EXTENSION: 2281 LOCATION: P4
B&V PROJECT: 18875
B&V PHASE: 040
B&V FILE:
DATE: JUNE 22, 1994

NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 3

NOTE TO RECEIVING OPERATOR

In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME:

OPERATOR'S INITIALS:

SUBJECT: CAPITAL COSTS FOR UNIT CONFIGURATION STUDY

MESSAGE: Attached are the capital cost estimates for the two on one combined cycle configuration and the two, one on one combined cycle configuration. These capital cost figures are for use in the unit configuration study only and are meant to be accurate enough for comparative purposes only. Significant assumptions are as follows.

1. The basis for the two on one cost is the estimate contained in the B&V engineering services proposal with a CTG unit cost of \$28,500,000 and other minor revisions.
2. The total direct cost for the two, one on one combined cycle units is estimated as 8.0 percent higher than for the two on one unit. Of this total cost, 55 percent is assumed to be for the first unit and 45 percent for the second unit. These figures are B&V "ballpark" estimates.
3. Other assumptions are as listed on the attached spreadsheets.

I will fax you a typical cash flow tomorrow (6/23).

Please call me at 913-339-2281 if you have questions.

cc: CJS

FLORIDA POWER CORPORATION
POLK COUNTY PROJECT
PROJECT COST ESTIMATE

B&V PROJECT 18875
B&V FILE 26.0200
JUNE 22, 1994

TWO 235 MW ONE ON ONE COMBINED CYCLE PLANTS

COST CATEGORY	FIRST PLANT COST	SECOND PLANT COST	BASIS
	\$1,000	\$1,000	
TOTAL DIRECT CAPITAL COST	107,958	88,329	6/93 DOLLARS
CONTINGENCY	10,796	8,833	10 % OF TOTAL DIRECT
SUBTOTAL	118,754	97,162	TOTAL DIRECT + CONTINGENCY
ESCALATION	25,592	26,844	5.0 % APR FOR 4 YRS/5 YRS
ENGINEERING & CONST MANAGEMENT	10,000	2,500	ESTIMATE
SUBTOTAL	154,346	126,506	SUBTOTAL + ESCAL + ENGR/CONST MGMNT
AFUDC	19,293	15,813	12.5 % OF SUBTOTAL
TOTAL PROJECT COST	173,639	142,320	SUBTOTAL + AFUDC
TOTAL PROJECT COST/MW	739	606	TOTAL PROJECT COST/235 MW

06/22/94

19:25

B&V PAR DIV

NO. 546

P002

FLORIDA POWER CORPORATION
POLK COUNTY PROJECT
PROJECT COST ESTIMATE

B&V PROJECT 18875
B&V FILE 26.0200
JUNE 22, 1994

ONE 470 MW TWO ON ONE COMBINED CYCLE PLANT

COST CATEGORY	COST	BASIS
	\$1,000	
TOTAL DIRECT CAPITAL COST	181,748	6/93 DOLLARS
CONTINGENCY	18,175	10 % OF TOTAL DIRECT
SUBTOTAL	199,922	TOTAL DIRECT + CONTINGENCY
ESCALATION	43,084	5.0 % APR FOR 4 YRS
ENGINEERING & CONST MANAGEMENT	12,000	ESTIMATE
SUBTOTAL	255,007	SUBTOTAL + ESCAL + ENGR/CONST MGMNT
AFUDC	31,876	12.5 % OF SUBTOTAL
TOTAL PROJECT COST	286,883	SUBTOTAL + AFUDC
TOTAL PROJECT COST/KW	610	TOTAL PROJECT COST/470 MW

DO NOT WRITE

18:47

BSV PLAN DIV

NO. 546

1985



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

FAX NUMBER: 913-339-2934 913-339-2936 913-339-2939

FACSIMILE TRANSMISSION

TO: RANDY LEHNHOFF B&V PROJECT: 18875
COMPANY: EPC B&V PHASE: 040
FAX NUMBER: 813-866-4994 B&V FILE: _____
TELEPHONE NUMBER: _____
FROM: STEVE CLARK JMC DATE: JUNE 29, 1994
EXTENSION: 2281 LOCATION: P4

NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 2

NOTE TO RECEIVING OPERATOR

In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME: _____ OPERATOR'S INITIALS: _____

SUBJECT: CAPITAL COSTS FOR UNIT CONFIGURATION STUDY

MESSAGE: Attached are the capital cost estimates for the phased two on one combined cycle configuration. These capital cost figures are for use in the unit configuration study and are meant to be accurate enough for comparative purposes only.

The basis for this cost estimate is the estimate contained in the B&V engineering services proposal with a CTG unit cost of \$28,500,000 and other minor revisions. Other assumptions are as listed on the attached spreadsheet.

The split cash flow you requested for the two, one on one configuration will be faxed to you separately today by Larry Lucas of B&V.

You also enquired what makes the two, one on one configuration 8 percent higher in capital cost than the one, two on one configuration. The principal reason for higher cost is that two 85 MW steam turbine generators and related equipment (bus duct, circuit breakers, GSU transformers, condenser, condensate pumps, circulating water system, etc.) are more expensive than one 170 MW steam turbine generator and related equipment. We do not have a line item capital cost comparison at this time. However, we do believe that the 8 percent cost increase is accurate enough for the purposes of the unit configuration study.

Please call me at 913-339-2281 if you have questions.

cc: CJS, MJE, RLV, LKL

FLORIDA POWER CORPORATION
POLK COUNTY PROJECT
PROJECT COST ESTIMATE

B&V PROJECT 18875
B&V FILE 26.0200
JUNE 29, 1994

PHASED 470 MW TWO ON ONE COMBINED CYCLE PLANT *

COST CATEGORY	PHASE I COST	PHASE II COST	BASIS
	\$1,000	\$1,000	
TOTAL DIRECT CAPITAL COST	127,778	53,970	6/93 DOLLARS
CONTINGENCY	12,778	5,397	10 % OF TOTAL DIRECT
	140,556	59,367	TOTAL DIRECT + CONTINGENCY
SUBTOTAL	30,291	18,402	5.0 % APR FOR 4 YRS/5 YRS
ESCALATION	11,800	750	ESTIMATE
ENGINEERING & CONST MANAGEMENT			
	182,646	76,519	SUBTOTAL + ESCAL + ENGR/CONST MGMT
SUBTOTAL	22,831	9,565	12.5 % OF SUBTOTAL
AFUDC			
	205,477	86,084	SUBTOTAL + AFUDC
TOTAL PROJECT COST	874	366	TOTAL PROJECT COST/235 MW
TOTAL PROJECT COST/KW			

- * PHASE I IS COMPLETE 470 MW COMBINED CYCLE UNIT, LESS ONE CTG, ONE HRSG, AND RELATED EQUIPMENT.
PHASE II INCLUDES THE SECOND CTG, HRSG, AND RELATED EQUIPMENT TO COMPLETE THE 2 ON 1 UNIT.
PHASE I HAS A COMMERCIAL OPERATION DATE OF JULY, 1998 AND PHASE II IS JULY, 1999.

06/29/94

18:11

B&V PAR DIV

NO. 978

P002

Jun. 29. 1994 4:55PM

B&V POWER DIV M BLDG

No. 7784 P. 1/9



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

FAX NUMBER: 913-339-7050

FACSIMILE TRANSMISSION

TO: Randy Lehnhoff
COMPANY: Florida Power Corporation
FAX NUMBER: 813-866-4994
TELEPHONE NUMBER: _____
FROM: Kevin Bogner
EXTENSION: 4102 LOCATION: M1B1

B&V PROJECT: 18875
B&V PHASE: 040
B&V FILE: _____
DATE: June 29, 1994

NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 9

NOTE TO RECEIVING OPERATOR
In the event of incomplete transmission, please call (913) 339-4237.

TRANSMITTAL DATE/TIME: _____ OPERATOR'S INITIALS: _____

SUBJECT: Polk County Anticipated Cash Flows

MESSAGE: Attached are three cash flows for the different configurations, a graphical representation of the three cash flows and a memo explaining assumptions.

cc:
C.J. Schutty
S.M. Clark
L.K. Lucas

BLACK & VEATCH

MEMORANDUM

Florida Power Corporation
Polk County
Polk County Anticipated Cash Flow

B&V Project 18875.040

June 29, 1994

To: Randy Lehnhoff

From: Kevin Bogner *KB*

Attached are the cash flow reports for the Polk County project. In order to establish the cash flows, the following assumptions were made: The Stage 2 2 on 1 and the Stage 1 1 on 1 engineering, procurement and construction time frames were kept consistent based on the project summary schedule. The percentage difference between the two configurations varied because of the equipment procurement and the scope of construction.

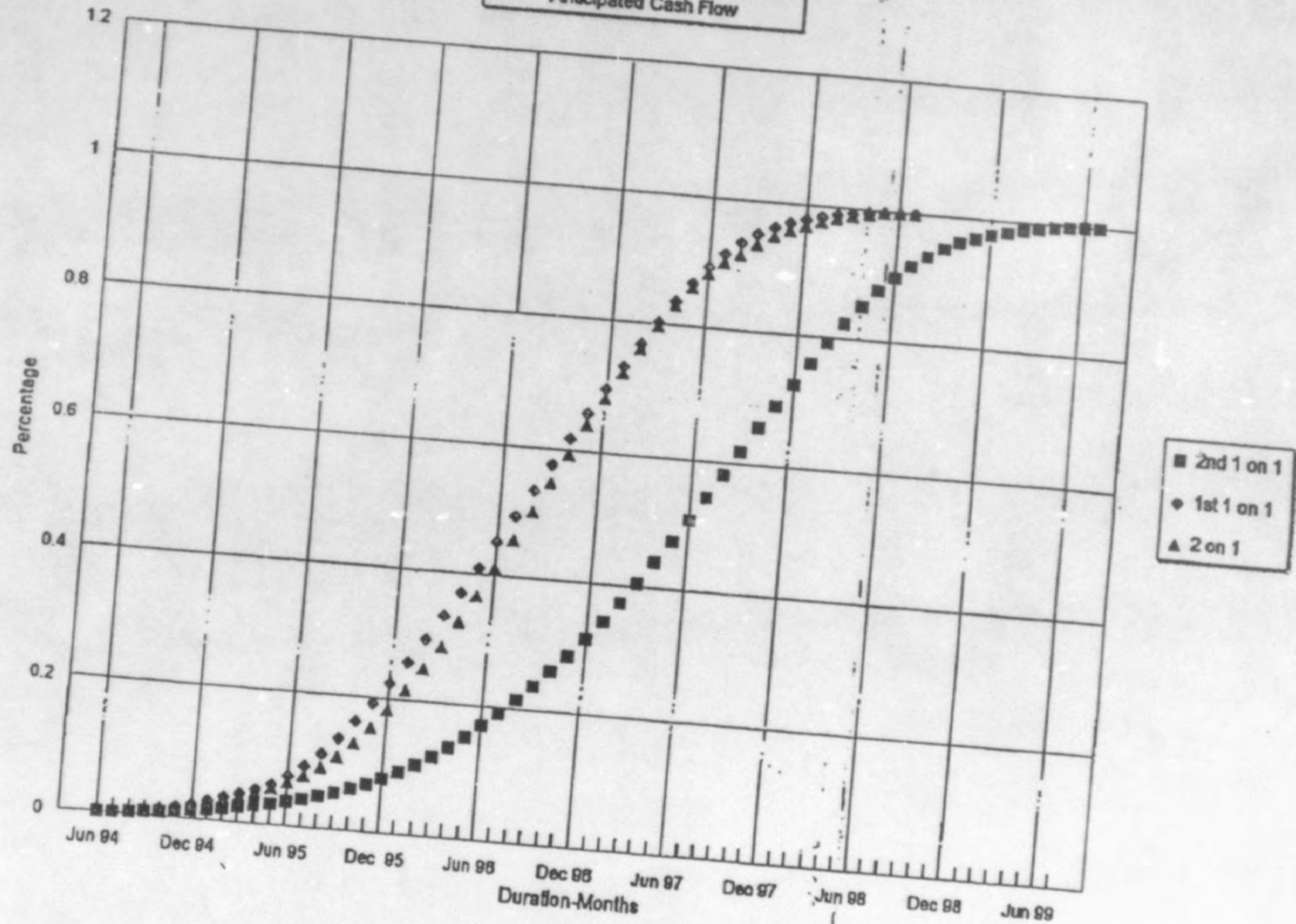
The Stage 3 1 on 1 engineering was assumed to be substantially complete. Therefore, the engineering percentages were low at the start of the cash flow. Procurement was spread out over an extended period due to progress payments on the major equipment. The construction duration remained the same as the Stage 1 1 on 1 except that the start of construction and the commercial operation dates were extended by one year.

cc:

C.J. Schutty
S.M. Clark
L.K. Lucas

Polk County Project

Anticipated Cash Flow



Jun. 29. 1994 4:56PM B&V POWER DIV M BLDG

No. 7784 P. 3/9

Anticipated Cash Flow
Florida Power Corp
Polk County Project
1on1 235MW Stage 3

Payment Due Date	Percent of Total To Be Invoiced
June 1, 1994	0.001
July 1, 1994	0.001
August 1, 1994	0.001
September 1, 1994	0.002
October 1, 1994	0.002
November 1, 1994	0.002
December 1, 1994	0.003
January 1, 1995	0.003
February 1, 1995	0.004
March 1, 1995	0.004
April 1, 1995	0.004
May 1, 1995	0.004
June 1, 1995	0.005
July 1, 1995	0.005
August 1, 1995	0.006
September 1, 1995	0.007
October 1, 1995	0.008
November 1, 1995	0.009
December 1, 1995	0.010
January 1, 1996	0.012
February 1, 1996	0.013
March 1, 1996	0.014
April 1, 1996	0.016
May 1, 1996	0.017
June 1, 1996	0.019
July 1, 1996	0.020
August 1, 1996	0.022
September 1, 1996	0.023
October 1, 1996	0.024
November 1, 1996	0.025
December 1, 1996	0.027
January 1, 1997	0.029
February 1, 1997	0.031
March 1, 1997	0.032

Jun. 29, 1994

4:57PM

B&V POWER DIV M BLDG

No. 7784 P. 5/9

Anticipated Cash Flow
Florida Power Corp
Polk County Project
1on1 235MW Stage 3

Payment Due Date	Percent of Total To Be Invoiced
April 1, 1997	0.034
May 1, 1997	0.034
June 1, 1997	0.035
July 1, 1997	0.037
August 1, 1997	0.037
September 1, 1997	0.037
October 1, 1997	0.037
November 1, 1997	0.035
December 1, 1997	0.035
January 1, 1998	0.034
February 1, 1998	0.032
March 1, 1998	0.030
April 1, 1998	0.030
May 1, 1998	0.025
June 1, 1998	0.023
July 1, 1998	0.020
August 1, 1998	0.017
September 1, 1998	0.013
October 1, 1998	0.011
November 1, 1998	0.009
December 1, 1998	0.007
January 1, 1999	0.006
February 1, 1999	0.005
March 1, 1999	0.004
April 1, 1999	0.003
May 1, 1999	0.002
June 1, 1999	0.002
July 1, 1999	0.001
Total	1.000

Anticipated Cash Flow
Florida Power Corp
Polk County Project
1 on 1 235MW STAGE 1

Payment Due Date	Percent of Total To Be Invoiced
June 1, 1994	0.001
July 1, 1994	0.001
August 1, 1994	0.002
September 1, 1994	0.003
October 1, 1994	0.004
November 1, 1994	0.004
December 1, 1994	0.005
January 1, 1995	0.006
February 1, 1995	0.006
March 1, 1995	0.007
April 1, 1995	0.007
May 1, 1995	0.008
June 1, 1995	0.010
July 1, 1995	0.012
August 1, 1995	0.015
September 1, 1995	0.018
October 1, 1995	0.022
November 1, 1995	0.025
December 1, 1995	0.028
January 1, 1996	0.031
February 1, 1996	0.034
March 1, 1996	0.036
April 1, 1996	0.039
May 1, 1996	0.042
June 1, 1996	0.044
July 1, 1996	0.045
August 1, 1996	0.046
September 1, 1996	0.047
October 1, 1996	0.046
November 1, 1996	0.045
December 1, 1996	0.043
January 1, 1997	0.041
February 1, 1997	0.039
March 1, 1997	0.036

Anticipated Cash Flow
Florida Power Corp
Polk County Project
1 on 1 235MW STAGE 1

Payment Due Date	Percent of Total To Be Invoiced
April 1, 1997	0.032
May 1, 1997	0.028
June 1, 1997	0.024
July 1, 1997	0.019
August 1, 1997	0.014
September 1, 1997	0.018
October 1, 1997	0.015
November 1, 1997	0.011
December 1, 1997	0.009
January 1, 1998	0.008
February 1, 1998	0.007
March 1, 1998	0.006
April 1, 1998	0.005
May 1, 1998	0.003
June 1, 1998	0.002
July 1, 1998	0.001
Total	1.000

Anticipated Cash Flow
Florida Power Corp
Polk County Project
2 on 1 470MW

Payment Due Date	Percent of Total To Be Invoiced
June 1, 1994	0.001
July 1, 1994	0.001
August 1, 1994	0.002
September 1, 1994	0.003
October 1, 1994	0.004
November 1, 1994	0.005
December 1, 1994	0.006
January 1, 1995	0.006
February 1, 1995	0.007
March 1, 1995	0.007
April 1, 1995	0.008
May 1, 1995	0.010
June 1, 1995	0.014
July 1, 1995	0.017
August 1, 1995	0.021
September 1, 1995	0.024
October 1, 1995	0.027
November 1, 1995	0.029
December 1, 1995	0.032
January 1, 1996	0.034
February 1, 1996	0.036
March 1, 1996	0.037
April 1, 1996	0.038
May 1, 1996	0.040
June 1, 1996	0.041
July 1, 1996	0.042
August 1, 1996	0.042
September 1, 1996	0.042
October 1, 1996	0.041
November 1, 1996	0.040
December 1, 1996	0.039
January 1, 1997	0.037
February 1, 1997	0.036
March 1, 1997	0.034

Anticipated Cash Flow
Florida Power Corp
Polk County Project
2 on 1 470MW

Payment Due Date	Percent of Total To Be Invoiced
April 1, 1997	0.032
May 1, 1997	0.029
June 1, 1997	0.027
July 1, 1997	0.023
August 1, 1997	0.020
September 1, 1997	0.016
October 1, 1997	0.012
November 1, 1997	0.009
December 1, 1997	0.007
January 1, 1998	0.006
February 1, 1998	0.005
March 1, 1998	0.004
April 1, 1998	0.003
May 1, 1998	0.002
June 1, 1998	0.001
July 1, 1998	0.001
Total	1.000

**BLACK & VEATCH**

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

FAX NUMBER: 913-339-2934 913-339-2935 913-339-2939

F A C S I M I L E T R A N S M I S S I O NTO: RANDY LEHNHOFFCOMPANY: FPCFAX NUMBER: 813-866-4994TELEPHONE NUMBER: FROM: STEVE CLARK *me*EXTENSION: 2281LOCATION: P4B&V PROJECT: 18875B&V PHASE: 040B&V FILE: DATE: JUNE 28, 1994NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 1**NOTE TO RECEIVING OPERATOR**

In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME: OPERATOR'S INITIALS: SUBJECT: **ESTIMATED SUBSTATION COSTS FOR UNIT CONFIGURATION STUDY**

MESSAGE: Estimated substation costs are as follows.

1. For 2 on 1, 470 MW Combined Cycle Unit: \$7,700,000 total direct cost. Assumes 4 bay design with 1 bay for each of 3 GSU transformers and 1 bay for startup/aux transformer. Four outgoing transmission lines assumed.
2. For Two, 1 on 1 235 MW Combined Cycle Units: \$5,800,000 for first 1 on 1 and \$3,800,000 for second 1 on 1 unit for a total of \$9,600,000. Assumes first 1 on 1 unit includes 3 bays (1 for each of 2 GSU transformers and 1 for startup/aux transformer) and 3 transmission lines out. Assumes 2 additional bays for second 1 on 1 unit (1 for each of 2 GSU transformers) and 1 additional transmission line out.

Note that above cost estimates are preliminary and are to be used only for the unit configuration study. The cost figures include all direct costs, including installation and are current (July 1, 1994) dollars.

Please call me at 913-339-2281 or Bill Burnett at 913-339-2111 if you have questions.

cc: CJS
MJE
RVN
Bill Burnett



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

FAX NUMBER: 913-339-2934 913-339-2936 913-339-2939

FACSIMILE TRANSMISSION

TO: Randy Lehnhoff	B&V PROJECT: 18875
COMPANY: Florida Power Corporation	B&V PHASE: 040
FAX NUMBER: (813) 866-4994	B&V FILE: _____
TELEPHONE NUMBER: (813) 866-4033	DATE: June 28, 1994
FROM: R. L. Van Norden	
EXTENSION: 7760 LOCATION: P4B4	

NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 13

NOTE TO RECEIVING OPERATOR

In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME: _____ OPERATOR'S INITIALS: _____

SUBJECT: Response to Data Request

MESSAGE: In a partial response to the request for load model information received June 13, 1994, the following information is presented:

Item 1. The degraded performance sheets are attached including notes indicating the amount of degradation applied as requested.

Item 8. The plant equivalent availabilities are as follows:

1-2x1 plant, 200 starts per year:	92.13 percent
1-2x1 plant, 300 starts per year:	91.97 percent
2-1x1 plants, 200 starts per year:	92.48 percent
2-1x1 plants, 300 starts per year:	91.43 percent

The differences between cases is primarily dependent on whether the combustion turbine or steam turbine maintenance in a given year was limiting. If the steam turbine was shut down, it was assumed that both combustion turbines were also shut down. If the combustion turbine maintenance was limiting, it was assumed that the second combustion turbine and the steam turbine would be operating in the 2x1 cases.

Item 9. The plant forced outage rates are 6.85 percent for the 2x1 plant and 3.97 percent for the 1x1 plants. This is based on a forced outage rate of 3 percent for each combustion turbine and HRSG and a forced

Florida Power Corporation
Mr. Randy Lehnhoff

B&V Project 18875.040
June 28, 1994

outage rate of 1 percent for the steam turbine and balance of plant.

Item 10. The maintenance schedule for the first 10 years is attached. The following years would follow the same pattern. The schedules would be the same for the 2x1 and 1x1 cases.

Item 11. A breakdown of the fixed and variable O&M costs with the assumption list is attached. The fixed costs do not vary with the number of starts per year.

Information for the remaining items of the data request will be following shortly.

cc: C. J. Schutty
S. M. Clark
M. J. Eddington

Florida Power Corporation
Folk County Project

8&V Project 18877.040
08/26/94

Summary

	2 CTGs				1 CTG			
	2x1.7FA Units				2x1.7FA Units			
	Base Load Natural Gas 85 F. 48% RH	80% Load Natural Gas 85 F. 48% RH	80% Load Natural Gas 85 F. 48% RH	40% Load Natural Gas 85 F. 48% RH	Base Load Natural Gas 85 F. 48% RH	80% Load Natural Gas 85 F. 48% RH	80% Load Natural Gas 85 F. 48% RH	40% Load Natural Gas 85 F. 48% RH
ESTIMATED DEGRADED PERFORMANCE								
No. 1 Combustion Turbine Output, kW	123,089	88,250	73,984	48,033	123,089	88,250	73,984	48,033
No. 2 Combustion Turbine Output, kW	123,089	88,250	73,984	48,033	0	0	0	0
No. 1 Steam Turbine Output, kW	162,831	138,712	123,808	108,810	74,309	88,860	58,713	41,188
No. 2 Steam Turbine Output, kW	0	0	0	0	0	0	0	0
Total Gross Plant Output, kW	386,008	326,212	271,899	200,876	197,398	184,870	132,677	88,181
Auxiliary Power, kW	10,520	10,180	8,860	8,480	2,780	2,808	2,520	2,230
Total Net Plant Output, kW	386,288	326,032	261,888	194,185	199,618	187,210	129,247	88,841
CT Heat Consumption, MBtu/h (99V)	2,902.8	2,816.4	2,151.7	1,737.4	1,451.4	1,288.7	1,075.8	888.7
CT Heat Consumption, MBtu/h (LHV)	2,818.9	2,270.4	1,838.0	1,585.8	1,308.8	1,135.2	898.5	781.8
CTG Gross Heat Rate, Btu/kWh, (LHV)	10,828	11,554	13,108	16,995	10,828	11,554	13,108	16,995
Net Plant Heat Rate, Btu/kWh (99V)	7,428	7,751	8,219	8,846	7,854	8,013	8,680	8,852
Net Plant Heat Rate, Btu/kWh (LHV)	6,737	6,985	7,401	8,082	6,988	7,221	7,761	8,806

NOTE: Performance has been adjusted to reflect life cycle average degradation.

Where

	2 CTGs				1 CTG			
	2x1.7FA Units				2x1.7FA Units			
	Base Load Natural Gas 60 F. 70% RH	80% Load Natural Gas 60 F. 70% RH	80% Load Natural Gas 60 F. 70% RH	40% Load Natural Gas 60 F. 70% RH	Base Load Natural Gas 60 F. 70% RH	80% Load Natural Gas 60 F. 70% RH	80% Load Natural Gas 60 F. 70% RH	40% Load Natural Gas 60 F. 70% RH
ESTIMATED DEGRADED PERFORMANCE								
No. 1 Combustion Turbine Output, kW	152,981	121,788	81,788	61,037	152,981	121,788	81,788	61,037
No. 2 Combustion Turbine Output, kW	152,981	121,788	81,788	61,037	0	0	0	0
No. 1 Steam Turbine Output, kW	181,711	188,187	188,773	118,932	69,181	78,829	88,874	87,877
No. 2 Steam Turbine Output, kW	0	0	0	0	0	0	0	0
Total Gross Plant Output, kW	486,433	392,780	329,345	239,908	228,532	197,822	180,880	118,813
Auxiliary Power, kW	10,880	10,590	10,100	8,820	2,880	2,880	2,680	2,880
Total Net Plant Output, kW	465,853	382,289	318,245	229,238	227,542	194,442	178,200	115,933
CT Heat Consumption, MBtu/h (99V)	3,880.4	2,894.9	2,470.5	1,875.4	1,880.2	1,447.5	1,235.3	888.7
CT Heat Consumption, MBtu/h (LHV)	3,028.3	2,408.8	2,226.3	1,778.4	1,514.1	1,304.4	1,113.2	888.2
CTG Gross Heat Rate, Btu/kWh, (LHV)	8,928	10,710	12,128	16,588	8,928	10,710	12,128	16,588
Net Plant Heat Rate, Btu/kWh (99V)	7,377	7,553	7,883	8,800	7,384	7,618	8,085	8,848
Net Plant Heat Rate, Btu/kWh (LHV)	6,648	6,808	7,178	7,788	6,654	6,884	7,288	7,871

NOTE: Performance has been adjusted to reflect life cycle average degradation as follows:

- 7.7 percent CTG output degradation including 2.0 percent for average recoverable losses.
- 4.8 percent CTG heat rate degradation including 1.0 percent for average recoverable losses.
- 1.0 percent CTG output degradation.

08/28/94

14:23

BAU PAR DIV

NO. 386

083

Florida Power Corporation
Palm County Project

Summer

ESTIMATED DEGRADED PERFORMANCE

No. 1 Combustion Turbine Output, kW
No. 2 Combustion Turbine Output, kW
No. 1 Steam Turbine Output, kW
No. 2 Steam Turbine Output, kW
Total Gross Plant Output, kW
Auxiliary Power, kW
Total Net Plant Output, kW

CT Heat Consumption, MBtu/h (DHW)
CT Heat Consumption, MBtu/h (LHV)

CTG Gross Heat Rate, Btu/kWh (DHW)
Net Plant Heat Rate, Btu/kWh (DHW)
Net Plant Heat Rate, Btu/kWh (LHV)

NOTE: Performance has been adjusted to reflect the cycle average degradation.

Winter

ESTIMATED DEGRADED PERFORMANCE

No. 1 Combustion Turbine Output, kW
No. 2 Combustion Turbine Output, kW
No. 1 Steam Turbine Output, kW
No. 2 Steam Turbine Output, kW
Total Gross Plant Output, kW
Auxiliary Power, kW
Total Net Plant Output, kW

CT Heat Consumption, MBtu/h (DHW)
CT Heat Consumption, MBtu/h (LHV)

CTG Gross Heat Rate, Btu/kWh (DHW)
Net Plant Heat Rate, Btu/kWh (DHW)
Net Plant Heat Rate, Btu/kWh (LHV)

NOTE: Performance has been adjusted to reflect the cycle average degradation as follows:
7.7 percent CTG output degradation including 2.0 percent for average recoverable losses.
4.3 percent CTG heat rate degradation including 1.0 percent for average recoverable losses.
1.0 percent STG output degradation.

BBV Project 18875.040
08/28/94

08/28/94

14:24

BBV PWR DIV

2 CTGs			
300% TFA Units			
Base Load Natural Gas	80% Load Natural Gas	80% Load Natural Gas	40% Load Natural Gas
80 F. 68% RH	80 F. 68% RH	80 F. 68% RH	80 F. 68% RH
123,089	98,260	73,984	48,083
123,089	98,260	73,984	48,083
76,504	68,909	61,251	62,182
76,504	68,909	61,251	62,182
247,181	233,717	270,437	202,388
10,980	10,140	8,800	8,440
284,711	323,577	280,831	182,848
2,803.8	2,518.4	2,181.7	1,737.4
2,815.9	2,270.4	1,838.0	1,585.4
19,828	11,554	15,108	15,885
7,407	7,788	8,258	8,004
6,705	7,017	7,440	8,114

1 CTG			
300% TFA Units			
Base Load Natural Gas	80% Load Natural Gas	80% Load Natural Gas	40% Load Natural Gas
80 F. 68% RH	80 F. 68% RH	80 F. 68% RH	80 F. 68% RH
123,089	98,260	73,984	48,083
0	0	0	0
76,504	68,909	61,251	62,182
0	0	0	0
188,598	188,858	135,218	101,184
5,820	5,152	4,308	2,608
182,908	187,718	130,918	87,794
1,451.4	1,259.7	1,075.8	888.7
1,308.0	1,136.2	988.5	782.8
10,828	11,554	12,108	13,885
7,538	7,788	8,218	8,083
8,781	7,020	7,408	8,005

2 CTGs			
300% TFA Units			
Base Load Natural Gas	80% Load Natural Gas	80% Load Natural Gas	40% Load Natural Gas
40 F. 70% RH	40 F. 70% RH	40 F. 70% RH	40 F. 70% RH
152,381	121,788	91,788	61,037
152,381	121,788	91,788	61,037
78,888	74,255	67,800	57,884
78,888	74,255	67,800	57,884
484,841	392,102	318,771	237,481
10,858	10,420	10,990	8,820
463,801	381,682	308,771	227,851
3,380.4	2,884.8	2,470.5	1,973.4
3,029.3	2,608.8	2,229.3	1,778.4
0,938	10,719	12,128	14,588
7,405	7,885	8,003	8,882
6,873	6,835	7,212	7,808

1 CTG			
300% TFA Units			
Base Load Natural Gas	80% Load Natural Gas	80% Load Natural Gas	40% Load Natural Gas
40 F. 70% RH	40 F. 70% RH	40 F. 70% RH	40 F. 70% RH
152,381	121,788	91,788	61,037
0	0	0	0
78,888	74,255	67,800	57,884
0	0	0	0
292,829	189,081	188,388	118,730
8,170	8,880	5,780	5,880
228,181	180,471	183,808	113,170
1,880.3	1,647.5	1,335.3	886.7
1,516.1	1,304.4	1,113.2	888.2
8,838	10,730	12,128	14,588
7,430	7,818	8,042	8,718
8,886	6,888	7,247	7,857

NO. 395... D84

COMBUSTION TURBINE AND STEAM TURBINE MAINTENANCE REQUIREMENTS

Based on 200 starts per year, 60% capacity factor

	Interval, Operating Hours	Equipment Downtime for Maintenance (Days)									
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
CTG Combustion Inspection	8,000		5		5		5		5		
CTG Hot Gas Path Inspection	21,024					13				13	
CTG Major Overhaul	48,000										18
STG Annual Inspection	8,000		12		12	12		12			12
STG Major Overhaul	40,000								33		

Notes:

1. Downtime for planned maintenance (inspection or overhaul) is based on three 8-hour shifts or two 12-hour shifts per day.
2. Two additional days are required for either the CTG or STG to cool down prior to maintenance.
3. Maintenance activities are planned as follows. The first CTG and STG (if necessary) are taken off-line simultaneously, allowed to cool down, and then inspected or overhauled. Two days before the first CTG is completed, the second CTG is taken off-line to allow cooling (only applicable if the STG is not down for maintenance, otherwise second CTG would have been off-line).

COMBUSTION TURBINE AND STEAM TURBINE MAINTENANCE REQUIREMENTS

Based on 300 starts per year, 60% capacity factor

	Interval, Operating Hours	Equipment Downtime for Maintenance (Days)									
		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
CTG Combustion Inspection	8,000										
CTG Hot Gas Path Inspection	14,016		5			5		6			6
CTG Major Overhaul	42,048			13			13				
STG Annual Inspection	8,000									18	
STG Major Overhaul	40,000		12		12	12		12	33		12

Notes:

1. Downtime for planned maintenance (inspection or overhaul) is based on three 8-hour shifts or two 12-hour shifts per day.
2. Two additional days are required for either the CTG or STG to cool down prior to maintenance.
3. Maintenance activities are planned as follows. The first CTG and STG (if necessary) are taken off-line simultaneously, allowed to cool down, and then inspected or overhauled. Two days before the first CTG is completed, the second CTG is taken off-line to allow cooling (only applicable if the STG is not down for maintenance, otherwise second CTG would have been off-line).

05/28/94

14:25

BLU PAR DIV

NO. 386

P06

06/28/94

14:25

B&U PWR DIV

NO. 386 ... 087...

Florida Power Corporation
Polk County

Operating and Maintenance Assumption List

- 60 percent capacity factor
- 8.81 percent discount rate
- 3.15 percent escalation rate (1994 to 2004)
- 3.50 percent escalation rate (2005 to 2022)
- Combustion inspection interval - 8,000 hours
- Hot Gas Path inspection interval - 21,024 hours (for 200 starts per year)
- Hot Gas Path inspection interval - 14,016 hours (for 300 starts per year)
- Major inspection interval - 48,000 hours (for 200 starts per year)
- Major inspection interval - 42,048 hours (for 300 starts per year)
- ~~Combustion turbine recommended inspection, replacement, and repair~~
- ~~Intervals and costs provided by General Electric~~
- Dry low NO_x combustor
- 25 year cycle life
- Steam turbine minor inspection every 8,000 hours of operation
- Steam turbine major inspection every 40,000 hours of operation
- Demineralized water treatment is not included in the BOP line item
- BOP line item is estimated and includes consumables and other BOP items
- Estimated plant staff requirement of 10
- Estimated plant salary of \$53,000/staff member (\$1994)
- Estimated annual supply and material cost
- Estimated annual rental equipment costs
- Estimated annual contracted service costs
- Permitting costs are not included
- Estimated annual routine maintenance costs
- 1998 commercial operation data

Florida Power Corporation - Polk County 1st vs 2nd Study
General Electric TFA 2nd Combined Cycle Plant Operating and Maintenance Cost Evaluation

06/28/94

06/28/94

14:26

EAU PAR DU

NO. 385

008

Commercial Operation Date
 Discount Rate 1, percent
 Economic Life, years

1998
 8.81%
 25

O&M Escalation (1994 to 2000), percent
 O&M Escalation (2000 to 2017), percent

1.13%
 3.50%

Year	Present Worth Factor	Escalation	Escalated Staff Cost	Present Worth Staff Cost	Escalated Supplies and Materials	Present Worth Supplies and Materials	Escalated Rooms	Present Worth Rooms	Escalated Customer Services	Present Worth Customer Services	Escalated Routine Maintenance	Present Worth Routine Maintenance	Total		
													Major Fixed Costs		
													Escalated Total	Present Worth Total	
1998	0.9190	1.0315	400,000	551,430	40,000	55,140	22,840	28,310	36,030	37,820	546,040	530,210	1,386,280	1,386,280	
1999	0.8446	1.0315	411,500	572,340	41,800	57,370	23,350	29,720	38,380	40,310	563,870	485,150	1,346,300	1,337,190	
2000	0.7742	1.0315	424,400	495,530	43,640	49,550	24,890	31,700	40,320	42,740	601,340	447,500	1,388,810	1,078,040	
2001	0.7154	1.0315	438,500	449,740	45,550	46,980	26,430	33,730	43,130	45,320	621,230	443,180	1,472,580	1,083,970	
2002	0.6536	1.0315	453,200	445,330	47,920	44,530	28,050	36,800	46,080	47,910	640,390	440,120	1,477,480	968,790	
2003	0.5925	1.0315	700,640	422,140	70,040	42,210	26,440	33,950	68,080	39,320	680,990	398,270	1,534,230	918,380	
2004	0.5358	1.0315	722,710	400,300	72,370	40,020	27,270	35,300	68,180	37,740	681,810	377,540	1,572,340	870,640	
2005	0.4809	1.0320	763,170	388,480	76,340	38,150	28,800	38,000	72,010	36,630	730,140	355,500	1,571,340	870,640	
2006	0.4277	1.0320	790,000	369,540	79,810	36,850	29,810	39,940	74,200	34,880	745,370	348,520	1,711,020	843,130	
2007	0.4194	1.0320	817,740	351,500	81,730	35,190	30,800	43,270	77,140	33,140	771,630	331,800	1,771,980	764,680	
2008	0.3629	1.0320	846,300	334,530	84,640	33,440	32,440	46,820	79,940	31,540	796,400	315,630	1,841,340	722,780	
2009	0.3451	1.0320	873,980	318,050	87,820	31,800	33,850	49,630	82,430	30,800	836,400	300,030	1,905,680	681,880	
2010	0.3337	1.0320	905,080	302,510	90,080	30,250	34,310	51,410	85,370	28,540	853,330	285,790	1,972,370	652,380	
2011	0.3066	1.0320	938,370	287,750	93,840	28,780	35,410	56,880	88,520	27,140	882,300	272,440	2,041,400	625,680	
2012	0.2818	1.0320	971,230	273,710	97,120	27,370	36,450	60,330	91,400	25,820	916,130	258,720	2,112,880	595,430	
2013	0.2590	1.0320	1,005,210	260,330	100,520	26,050	37,800	64,820	94,820	24,540	948,310	243,610	2,186,790	566,570	
2014	0.2380	1.0320	1,040,290	247,640	104,040	24,780	39,260	69,530	98,140	23,240	981,510	233,430	2,262,340	538,740	
2015	0.2188	1.0320	1,076,810	235,540	107,680	23,550	40,430	74,800	101,580	22,230	1,015,880	223,290	2,340,380	512,680	
2016	0.2010	1.0320	1,114,490	224,040	111,450	22,440	42,820	80,130	105,130	21,140	1,051,480	211,580	2,420,330	487,680	
2017	0.1841	1.0320	1,153,500	213,130	115,130	21,310	44,200	86,810	108,810	20,300	1,088,210	201,070	2,501,400	465,630	
2018	0.1684	1.0320	1,193,870	202,730	119,390	20,270	45,050	92,600	112,620	19,130	1,126,500	191,230	2,583,680	441,030	
2019	0.1541	1.0320	1,235,640	192,830	123,570	19,280	46,400	98,780	116,540	18,180	1,165,730	181,920	2,667,400	419,500	
2020	0.1404	1.0320	1,278,910	183,430	127,890	18,340	48,200	104,980	120,640	17,300	1,204,520	175,840	2,752,220	399,920	
2021	0.1281	1.0320	1,323,670	174,470	132,770	17,430	49,900	111,500	124,870	16,440	1,243,730	164,800	2,838,610	379,500	
2022	0.1211	1.0320	1,370,000	165,940	137,900	16,500	51,600	118,240	129,240	15,600	1,292,440	154,570	2,926,340	361,030	
Sum of Present Worth (1998 \$)					8,033,200		800,300		393,140		737,800		7,578,300		17,476,000
Sum of Present Worth (1994 \$)					5,266,000		326,600		198,780		496,800		4,968,200		11,477,300
Contingency (70%)					1,853,300		105,300		39,700		99,400		99,700		2,291,300
Annual Levelized Fixed O&M Cost					431,300		63,300		23,000		59,800		59,700		1,178,300

Florida Power Corporation - Full County 2nd to 2nd Study
 Orono Electric TPA 2nd Constant Cycle Variable Operating and Minimum Cost Evaluation

1970
8.21.70
23

04/20/77

OMC Evolution 3700 - 2004 - present
OMC Evolution 3800 - 2002 - present
Capacity Factor, present

2.2
2.3
2.4

66-2894

14:27

BAU PAR DIV

NO. 386
1003

Health Power Corporation - Port County Ltd. v. 2nd Study
General Electric WPA 2nd Combined Cycle Vehicle Operating and Maintenance Cost Reduction

06/29/94

06/29/94

14:28

BAU PAR DIV

NO. 396

D16

Combined Operating Costs

1994

Discount Rate 1 percent

8.81%

Combined Life, years

25

CRS4 Residuals (1994 - 2024), present

5.17%

CRS4 Residuals (2025 - 2029), present

3.20%

Capacity Factor, percent

65%

Year	Present Worth Factor	Combined	Number of Assets	Operating Hours	Combined Number of Operating Hours	Combined Vehicle Major Maintenance Costs				Residual Vehicle Major Maintenance Costs		CRS4 Vehicle Major Maintenance Costs		CRS4 Vehicle Major Maintenance Costs		Total	
						Type of Inspection	Residual Labor	Present Worth Labor (\$)	Residual Materials	Present Worth Materials (\$)	Residual Materials	Present Worth Materials (\$)	Residual Materials	Present Worth Materials (\$)	Residual Materials	Present Worth Materials (\$)	Total Present Worth (\$)
1994	0.9130	1.0913	300	3,254	1,254		0	0	1,091,300	994,770	0	0	227,330	308,880	474,560	460,000	1,759,940
1995	0.8464	1.0913	300	3,254	10,533	CI	43,370	36,730	9,422,330	8,088,740	336,510	284,330	336,510	284,330	401,640	407,110	4,300,330
1996	0.7792	1.0913	300	3,254	13,798	BO	100,330	84,540	11,148,330	9,639,380	0	0	341,740	407,660	336,510	336,510	3,861,640
1997	0.7134	1.0913	300	3,254	21,084		0	0	0	0	337,890	285,370	343,330	407,660	336,510	336,510	3,361,640
1998	0.6534	1.0913	300	3,254	34,390	CI	47,340	39,870	769,690	663,340	349,620	291,980	337,330	407,660	336,510	336,510	2,861,640
1999	0.5923	1.0913	300	3,254	51,754	BO	206,340	173,340	4,300,330	3,669,400	0	0	343,330	407,660	336,510	336,510	2,361,640
2000	0.5354	1.0913	300	3,254	74,790	CI	30,630	25,330	611,340	524,330	360,730	297,470	343,330	407,660	336,510	336,510	1,861,640
2001	0.4809	1.0913	300	3,254	104,040		0	0	0	0	360,730	297,470	343,330	407,660	336,510	336,510	1,361,640
2002	0.4277	1.0913	300	3,254	141,300	ME	405,390	336,770	11,849,640	10,217,650	0	0	360,730	407,660	336,510	336,510	861,640
2003	0.3759	1.0913	300	3,254	184,530	CI	57,340	47,800	918,630	794,630	438,660	364,660	360,730	407,660	336,510	336,510	361,640
2004	0.3254	1.0913	300	3,254	234,840	BO	246,840	205,330	5,239,330	4,509,330	468,180	386,180	360,730	407,660	336,510	336,510	311,640
2005	0.2761	1.0913	300	3,254	292,070		0	0	0	0	0	0	360,730	407,660	336,510	336,510	261,640
2006	0.2280	1.0913	300	3,254	356,320	CI	66,660	55,170	1,018,640	881,640	489,390	396,660	360,730	407,660	336,510	336,510	211,640
2007	0.1810	1.0913	300	3,254	427,590	BO	273,730	228,660	12,017,640	10,481,640	514,670	426,670	360,730	407,660	336,510	336,510	161,640
2008	0.1351	1.0913	300	3,254	504,840	CI	87,390	72,330	1,099,330	937,630	0	0	360,730	407,660	336,510	336,510	111,640
2009	0.0902	1.0913	300	3,254	588,090		0	0	0	0	2,302,940	1,944,330	360,730	407,660	336,510	336,510	61,640
2010	0.0562	1.0913	300	3,254	676,340	ME	734,060	607,120	17,249,340	14,964,340	360,730	297,470	360,730	407,660	336,510	336,510	11,640
2011	0.0329	1.0913	300	3,254	769,590	CI	73,380	60,660	1,209,630	1,059,630	0	0	360,730	407,660	336,510	336,510	6,640
2012	0.0194	1.0913	300	3,254	867,840	BO	313,060	259,330	5,342,090	4,613,090	63,880	52,630	360,730	407,660	336,510	336,510	1,640
2013	0.0108	1.0913	300	3,254	970,090		0	0	0	0	63,880	52,630	360,730	407,660	336,510	336,510	640
2014	0.0061	1.0913	300	3,254	1,076,340	CI	83,380	68,660	1,340,330	1,164,330	0	0	360,730	407,660	336,510	336,510	140
2015	0.0034	1.0913	300	3,254	1,186,590	BO	340,430	283,660	7,049,330	6,104,330	68,660	56,660	360,730	407,660	336,510	336,510	40
2016	0.0018	1.0913	300	3,254	1,299,840	CI	89,330	73,660	1,496,090	1,296,090	3,756,930	3,164,930	360,730	407,660	336,510	336,510	0
2017	0.0009	1.0913	300	3,254	1,415,090		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
2018	0.0004	1.0913	300	3,254	1,532,340		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
2019	0.0001	1.0913	300	3,254	1,650,590		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
2020	0.0000	1.0913	300	3,254	1,769,840		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
2021	0.0000	1.0913	300	3,254	1,889,090		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
2022	0.0000	1.0913	300	3,254	2,008,340		0	0	0	0	0	0	360,730	407,660	336,510	336,510	0
Sum of Present Worth (1994-2022)								1,386,300		44,083,300		4,721,600		3,801,300		6,438,200	49,448,300
Sum of Present Worth (1994-2022)								774,330		11,336,630		1,008,330		1,394,330		4,389,630	44,389,630
Contingency (20%)								138,900		4,505,330		619,330		808,330		1,048,330	45,437,960
Annual Combined Vehicle CRS4 Cost								99,330		3,790,660		322,660		258,330		331,330	45,769,320

Florida Power Corporation - Polk County 1st to 2nd Study
General Electric 7FA Two 121a Combined Cycle Plant Operating and Maintenance Cost Evaluation

6/15/96

05/28/94

14:29

BAU PAR D1U

NO. 386

D11

Commercial Operation Date

1998

Discount Rate (percent)

8.83%

Economic Life, years

23

O&M Escalation (1998 to 2004), percent

3.17%

O&M Escalation (2005 to 2023), percent

3.50%

Year	Present Worth Fueling	Escalation	Escalated Staff Cost	Present Worth Staff Cost	Escalated Supplies and Materials	Present Worth Supplies and Materials	Escalated Rentals	Present Worth Rentals	Escalated Contracted Services	Present Worth Contracted Services	Escalated Routine Maintenance	Present Worth Routine Maintenance	Total Major Fixed Costs	
													Escalated Total	Present Worth Total
1998	0.9130	1.0115	630,000	554,430	40,000	33,140	22,640	20,830	54,000	52,030	423,640	372,230	1,341,880	1,237,430
1999	0.8848	1.0115	618,900	522,740	41,800	33,370	23,330	19,720	58,380	48,510	442,190	342,440	1,400,770	1,286,500
2000	0.7762	1.0115	438,400	495,530	43,840	49,530	34,950	18,700	40,230	44,740	442,430	314,340	1,449,930	1,274,780
2001	0.7134	1.0215	638,300	449,740	45,830	46,980	24,230	17,730	42,130	44,330	403,530	427,480	1,498,430	1,406,280
2002	0.6336	1.0115	679,230	445,330	47,930	44,730	23,630	16,830	64,080	43,010	704,380	442,140	1,541,780	1,470,830
2003	0.6025	1.0215	700,640	422,140	70,040	42,220	16,440	15,930	66,030	39,830	737,030	434,180	1,590,330	1,511,230
2004	0.5328	1.0215	722,730	480,380	72,270	40,820	27,270	15,300	68,180	37,780	749,980	445,380	1,649,130	1,501,330
2005	0.5049	1.0330	742,530	588,490	74,540	34,830	18,830	14,880	72,010	36,630	793,130	480,130	1,649,130	1,501,330
2006	0.4477	1.0330	790,000	589,540	79,000	34,830	19,830	13,940	74,330	34,880	819,980	583,480	1,793,340	1,671,730
2007	0.4299	1.0230	817,340	551,580	81,730	33,150	30,680	13,270	77,140	33,140	848,380	546,740	1,856,180	1,797,880
2008	0.3936	1.0330	844,380	554,330	84,640	33,440	31,940	12,820	79,840	31,540	878,380	546,930	1,921,040	1,734,930
2009	0.3401	1.0230	875,980	518,930	87,820	31,880	33,850	12,880	82,830	30,030	929,840	546,970	1,921,040	1,734,930
2010	0.3327	1.0230	906,640	502,530	90,680	30,130	34,280	11,470	85,330	28,540	940,230	530,830	1,988,500	1,721,880
2011	0.3064	1.0230	934,370	487,730	93,340	28,780	35,430	10,880	88,540	27,140	975,780	508,480	1,129,930	1,673,340
2012	0.2818	1.0330	971,230	477,730	97,120	27,370	36,430	10,730	91,480	25,830	1,027,880	494,830	1,284,470	1,621,280
2013	0.2580	1.0330	1,045,210	480,330	104,520	26,830	37,830	9,830	94,830	24,580	1,043,140	478,130	1,381,630	1,590,330
2014	0.2380	1.0330	1,040,380	447,640	104,380	24,380	39,280	9,830	96,140	23,380	1,079,630	454,930	1,361,680	1,543,280
2015	0.2182	1.0330	1,074,810	435,580	107,880	23,580	40,830	8,880	99,180	22,330	1,117,440	444,430	1,464,340	1,504,880
2016	0.2036	1.0330	1,114,490	424,840	111,430	22,430	42,030	8,430	102,130	21,480	1,158,230	432,730	1,520,430	1,465,880
2017	0.1848	1.0330	1,153,580	413,130	113,530	21,310	43,530	8,040	106,830	20,480	1,197,880	421,730	1,520,430	1,465,880
2018	0.1698	1.0330	1,182,870	402,730	119,390	20,270	45,030	7,680	112,430	19,130	1,234,930	410,380	1,621,230	1,427,330
2019	0.1561	1.0330	1,215,880	391,830	123,570	19,280	46,630	7,280	116,540	18,130	1,282,130	400,180	1,708,230	1,389,330
2020	0.1434	1.0330	1,278,930	380,430	127,890	18,340	48,180	6,880	120,640	17,380	1,327,140	390,380	1,901,880	1,326,330
2021	0.1318	1.0330	1,323,630	374,670	132,170	17,430	49,830	6,580	124,830	16,480	1,375,630	381,080	2,004,480	1,295,830
2022	0.1211	1.0330	1,370,880	369,940	137,030	16,630	51,630	6,280	129,340	15,680	1,421,880	372,230	2,109,620	1,276,330
Sum of Present Worth (1998 \$)				8,033,300		803,300		303,140		757,900		8,334,300		12,133,300
Sum of Present Worth (1974 \$)				5,366,480		536,600		198,780		494,800		5,463,300		11,854,800
Contingency (20%)				1,053,300		105,300		39,700		99,400		1,093,180		2,390,800
Annual Levelized Fixed O&M Cost				483,300		48,300		23,900		39,800		437,400		1,432,800

Pacific Power Corporation - 7th Census 1994 to 2004 Study
General Electric TFA Five Year Combined Cycle Variable Operating and Maintenance Cost Evaluation

0&M Escalation (1994 - 2004), percent 3.11%
0&M Escalation (2005 - 2013), percent 3.85%
Capacity Factor, percent 65%

Combined Operating Costs
Escalation Rate & percent
Economic Life, years

1994
8.81%
25

Commutational Operations Data			1994		1995		1996		1997		1998		1999		2000		2001		2002		2003		2004		2005		2006		2007		2008		2009		2010		2011		2012		2013		2014		2015		2016		2017		2018		2019		2020		2021		2022		2023		2024		2025		2026		2027		2028		2029		2030		2031		2032		2033		2034		2035		2036		2037		2038		2039		2040		2041		2042		2043		2044		2045		2046		2047		2048		2049		2050		2051		2052		2053		2054		2055		2056		2057		2058		2059		2060		2061		2062		2063		2064		2065		2066		2067		2068		2069		2070		2071		2072		2073		2074		2075		2076		2077		2078		2079		2080		2081		2082		2083		2084		2085		2086		2087		2088		2089		2090		2091		2092		2093		2094		2095		2096		2097		2098		2099		2100		2101		2102		2103		2104		2105		2106		2107		2108		2109		2110		2111		2112		2113		2114		2115		2116		2117		2118		2119		2120		2121		2122		2123		2124		2125		2126		2127		2128		2129		2130		2131		2132		2133		2134		2135		2136		2137		2138		2139		2140		2141		2142		2143		2144		2145		2146		2147		2148		2149		2150		2151		2152		2153		2154		2155		2156		2157		2158		2159		2160		2161		2162		2163		2164		2165		2166		2167		2168		2169		2170		2171		2172		2173		2174		2175		2176		2177		2178		2179		2180		2181		2182		2183		2184		2185		2186		2187		2188		2189		2190		2191		2192		2193		2194		2195		2196		2197		2198		2199		2200		2201		2202		2203		2204		2205		2206		2207		2208		2209		2210		2211		2212		2213		2214		2215		2216		2217		2218		2219		2220		2221		2222		2223		2224		2225		2226		2227		2228		2229		2230		2231		2232		2233		2234		2235		2236		2237		2238		2239		2240		2241		2242		2243		2244		2245		2246		2247		2248		2249		2250		2251		2252		2253		2254		2255		2256		2257		2258		2259		2260		2261		2262		2263		2264		2265		2266		2267		2268		2269		2270		2271		2272		2273		2274		2275		2276		2277		2278		2279		2280		2281		2282		2283		2284		2285		2286		2287		2288		2289		2290		2291		2292		2293		2294		2295		2296		2297		2298		2299		2300		2301		2302		2303		2304		2305		2306		2307		2308		2309		2310		2311		2312		2313		2314		2315		2316		2317		2318		2319		2320		2321		2322		2323		2324		2325		2326		2327		2328		2329		2330		2331		2332		2333		2334		2335		2336		2337		2338		2339		2340		2341		2342		2343		2344		2345		2346		2347		2348		2349		2350		2351		2352		2353		2354		2355		2356		2357		2358		2359		2360		2361		2362		2363		2364		2365		2366		2367		2368		2369		2370		2371		2372		2373		2374		2375		2376		2377		2378		2379		2380		2381		2382		2383		2384		2385		2386		2387		2388		2389		2390		2391		2392		2393		2394		2395		2396		2397		2398		2399		2400		2401		2402		2403		2404		2405		2406		2407		2408		2409		2410		2411		2412		2413		2414		2415		2416		2417		2418		2419		2420		2421		2422		2423		2424		2425		2426		2427		2428		2429		2430		2431		2432		2433		2434		2435		2436		2437		2438		2439		2440		2441		2442		2443		2444		2445		2446		2447		2448		2449		2450		2451		2452		2453		2454		2455		2456		2457		2458		2459		2460		2461		2462		2463		2464		2465		2466		2467		2468		2469		2470		2471		2472		2473		2474		2475		2476		2477		2478		2479		2480		2481		2482		2483		2484		2485		2486		2487		2488		2489		2490		2491		2492		2493		2494		2495		2496		2497		2498		2499		2500		2501		2502		2503		2504		2505		2506		2507		2508		2509		2510		2511		2512		2513		2514		2515		2516		2517		2518		2519		2520		2521		2522		2523		2524		2525		2526		2527		2528		2529		2530		2531		2532		2533		2534		2535		2536		2537		2538		2539		2540		2541		2542		2543		2544		2545		2546		2547		2548		2549		2550		2551		2552		2553		2554		2555		2556		2557		2558		2559		2560		2561		2562		2563		2564		2565		2566		2567		2568		2569		2570		2571		2572		2573		2574		2575		2576		2577		2578		2579		2580		2581		2582		2583		2584		2585		2586		2587		2588		2589		2590		2591		2592		2593		2594		2595		2596		2597		2598		2599		2600		2601		2602		2603		2604		2605		2606		2607		2608		2609		2610		2611		2612		2613		2614		2615		2616		2617		2618		2619		2620		2621		2622		2623		2624		2625		2626		2627		2628		2629		2630		2631		2632		2633		2634		2635		2636		2637		2638		2639		2640		2641		2642		2643		2644		2645		2646		2647		2648		2649		2650		2651		2652		2653		2654		2655		2656		2657		2658		2659		2660		2661		2662		2663		2664		2665		2666		2667		2668		2669		2670		2671		2672		2673		2674		2675		2676		2677		2678		2679		2680		2681		2682		2683		2684		2685		2686		2687		2688		2689		2690		2691		2692		2693		2694		2695		2696		2697		2698		2699		2700		2701		2702		2703		2704		2705		2706		2707		2708		2709		2710		2711		2712		2713		2714		2715		2716		2717		2718		2719		2720		2721		2722		2723		2724		2725		2726		2727		2728		2729		2730		2731		2732		2733		2734		2735		2736		2737		2738		2739		2740		2741		2742		2743		2744		2745		2746		2747		2748		2749		2750		2751		2752		2753		2754		2755		2756		2757		2758		2759		2760		2761		2762		2763		2764		2765		2766		2767		2768		2769		2770		2771		2772		2773		2774		2775		2776		2777		2778		2779		2780		2781		2782		2783		2784		2785		2786		2787		2788		2789		2790		2791		2792		2793		2794		2795		2796		2797		2798		2799		2800		2801		2802		2803		2804		2805		2806		2807		2808		2809		2810		2811		2812		2813		2814		2815		2816		2817		2818		2819		2820		2821		2822		2823		2824		2825		2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Florida Power Corporation - Polk County 811 vs 812 Study
 Overall Electric 77A Two 1250 Constant Cycle Variable Operating and Maintenance Cost Evaluation

Commenced Operation Date
 Discount Rate, percent
 Economic Life, years

1996
 8.81%
 25

0404 Escalation (1994 - 2000), percent
 0404 Escalation (2001 - 2025), percent
 Capital y Factor, percent

1.11%
 1.80%
 85%

Year	Present Worth Factor	Escalation	Number of Annual Starts	Annual Operating Hours	Quantity of Operating Hours	Combustion Turbine				Steam Turbine		EESD		BOP		Total		
						Major Maintenance Costs				Major Maintenance Costs		Major Maintenance Costs		Major Maintenance Costs		Major Maintenance Costs		
						Type of Inspection	Estimated Labor	Present Worth Labor (\$)	Estimated Materials	Present Worth Materials (\$)	Estimated	Present Worth	Estimated	Present Worth	Estimated	Present Worth	Estimated	Present Worth
1994	0.9138	1.0311	30	5,256	5,256		0	0	1,025,700	994,770	0	0	227,200	300,800	478,500	440,000	1,720,900	1,805,570
1995	0.8444	1.0311	30	5,256	5,256	CI	43,320	36,590	5,422,520	5,093,740	441,800	577,820	280,500	357,900	428,800	407,100	4,025,400	3,953,100
2000	0.7740	1.0311	30	5,256	5,256	BO	184,300	164,560	11,148,120	8,025,880	0	0	341,500	387,000	529,400	590,400	11,051,800	9,307,400
2001	0.7156	1.0311	30	5,256	5,256		0	0	0	0	449,600	525,600	349,500	377,800	523,400	574,900	1,304,400	1,407,700
2002	0.6556	1.0311	30	5,256	5,256	CI	47,500	39,670	709,600	700,300	449,400	557,000	257,200	300,000	341,800	401,500	2,404,200	2,575,600
2003	0.6023	1.0311	30	5,256	5,256	BO	184,500	165,140	4,300,800	3,670,400	0	0	340,500	390,000	529,400	590,400	11,051,800	9,307,400
2004	0.5508	1.0311	30	5,256	5,256	CI	30,400	25,000	811,840	449,540	513,600	585,200	279,400	324,000	376,600	437,500	2,228,200	1,305,500
2005	0.5005	1.0311	30	5,256	5,256		0	0	0	0	2,340,300	1,497,300	289,000	347,100	409,200	500,800	3,341,400	1,906,800
2006	0.4477	1.0311	30	5,256	5,256	BO	409,300	357,700	11,345,840	10,317,400	0	0	299,000	339,700	420,400	500,800	10,161,400	10,342,100
2007	0.4028	1.0311	30	5,256	5,256	CI	37,340	30,400	718,400	394,600	581,300	674,200	309,000	367,300	420,400	500,800	2,228,200	1,305,500
2008	0.3639	1.0311	30	5,256	5,256	BO	246,800	212,500	3,275,320	3,007,300	421,800	504,200	329,400	395,100	471,500	568,200	7,802,800	7,998,800
2009	0.3290	1.0311	30	5,256	5,256		0	0	0	0	0	0	0	0	0	0	0	0
2010	0.2973	1.0311	30	5,256	5,256	CI	45,400	37,070	1,818,440	999,800	603,400	700,000	340,500	401,500	471,500	568,200	2,228,200	1,305,500
2011	0.2686	1.0311	30	5,256	5,256	BO	273,700	236,900	12,417,440	11,053,000	479,300	568,200	380,500	457,100	540,400	648,000	14,073,400	13,311,600
2012	0.2418	1.0311	30	5,256	5,256	CI	67,300	54,800	1,251,000	307,400	0	0	347,700	405,400	471,500	568,200	2,228,200	1,305,500
2013	0.2178	1.0311	30	5,256	5,256		0	0	0	0	3,873,200	1,009,200	340,500	401,500	471,500	568,200	2,228,200	1,305,500
2014	0.1956	1.0311	30	5,256	5,256	BO	304,400	267,500	10,448,940	7,003,200	730,100	874,000	380,500	457,100	540,400	648,000	14,073,400	13,311,600
2015	0.1748	1.0311	30	5,256	5,256	CI	71,940	58,400	1,309,400	346,400	0	0	407,200	480,000	568,200	674,000	2,228,200	1,305,500
2016	0.1554	1.0311	30	5,256	5,256	BO	323,400	282,300	9,549,940	6,715,800	884,200	1,059,000	423,800	504,000	590,400	700,000	13,311,600	12,549,800
2017	0.1374	1.0311	30	5,256	5,256		0	0	0	0	820,900	194,000	456,700	540,400	648,000	774,000	2,228,200	1,305,500
2018	0.1204	1.0311	30	5,256	5,256	CI	89,300	72,400	1,341,200	327,700	0	0	459,800	540,400	648,000	774,000	2,228,200	1,305,500
2019	0.1044	1.0311	30	5,256	5,256	BO	349,400	304,200	11,448,300	7,993,400	895,300	1,059,000	447,800	534,000	629,400	740,000	13,311,600	12,549,800
2020	0.0894	1.0311	30	5,256	5,256	CI	89,300	72,400	1,434,600	334,700	4,301,800	707,200	444,200	534,000	629,400	740,000	13,311,600	12,549,800
2021	0.0753	1.0311	30	5,256	5,256	BO	479,400	414,600	16,894,400	11,404,200	0	0	509,200	600,000	700,000	820,000	16,894,400	15,824,200
2022	0.0621	1.0311	30	5,256	5,256		0	0	0	0	889,400	219,000	519,200	610,000	700,000	820,000	16,894,400	15,824,200
Sum of Present Worth (1994 \$)								1,138,300		40,063,900		6,156,900		1,841,800		5,438,800		48,514,000
Sum of Present Worth (1994 \$)								774,300		31,236,400		4,002,800		1,394,300		4,222,800		42,340,000
Contingency (25%)								154,500		6,305,500		812,800		346,300		840,300		8,312,800
Annual Levelized Variable O&M Cost								75,300		5,792,400		400,700		219,300		305,300		5,118,700

06/28/94

14:30

BLU PAR D1U

NO. 386

D13

06/22/94

19:28

B&U PWR DIU

NO. 796

D11

BLACK & VEATCH - FLORIDA POWER

ESTIMATED PERFORMANCE - PG7221(PA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	95	95	95	95	95
AMBIENT RELATIVE HUMID	- %	48	48	48	48	48
OUTPUT	- kW	133300.	106400.	80100.	53100.	27200.
HEAT RATE (LHV)	- Btu/kWh	10190.	11080.	12370.	15310.	22100.
HEAT CONS. (LHV) X10-6	- Btu/h	1358.3	1178.9	1006.9	813.0	601.1
EXHAUST FLOW X10-3	- lb/h	3099.0	2630.0	2327.0	1991.0	1762.0
EXHAUST TEMP	- Deg F.	1137.	1191.	1200.	1200.	1107.
EXHAUST HEAT X10-6	- Btu/h	856.1	774.2	697.1	601.1	483.7
NOX	- ppmvd @ 15% O2	12.	12.	12.	12.	107.
NOX AS NO2	- lb/h	65.	51.	48.	38.	248.
CO	- ppmvd	25.	25.	25.	*	*
CO	- lb/h	70.	58.	52.	*	*
UHC	- ppmvv	7.	7.	7.	*	*
UHC	- lb/h	12.	10.	9.	*	*
PART	- lb/h	9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

ARGON	0.88	0.87	0.88	0.89	0.88
NITROGEN	73.26	73.22	73.32	73.48	73.90
OXYGEN	12.50	12.39	12.72	13.20	14.40
CARBON DIOXIDE	3.66	3.72	3.56	3.34	2.79
WATER	9.70	9.80	9.53	9.10	8.03

SITE CONDITIONS

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	48
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20790
APPLICATION	-	3176 HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
 NOx EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
 NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(1).
 NOx LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE
 SPEEDTRONIC CONTROL SYSTEM.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
 JAH 6-9-92

05/22/94

19:21

BEU PWR DIV

BLACK & VEATCH - FLORIDA POWER

NO. 796

D12

ESTIMATED PERFORMANCE - PG7221(PA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	40	40	40	40	40
AMBIENT RELATIVE HUMID	- %	70	70	70	70	70
OUTPUT	- kW	165000.	131900.	99400.	66100.	32900.
HEAT RATE (LHV)	- Btu/kWh	9530.	10270.	11630.	13970.	19860.
HEAT CONS. (LHV)	X10-6 - Btu/h	1572.5	1354.6	1156.0	923.4	653.4
EXHAUST FLOW	X10-3 - lb/h	3500.0	2903.0	2500.0	2123.0	1901.0
EXHAUST TEMP	- Deg F.	1089.	1157.	1200.	1200.	1055.
EXHAUST HEAT	X10-6 - Btu/h	955.0	857.3	775.8	663.9	515.0
NOX AS NO2	- ppmvd @ 15% O2	12.	12.	12.	12.	124.
CO	- ppmvd	76.	65.	55.	44.	313.
CO	- lb/h	25.	25.	25.	*	*
UHC	- ppmv	80.	65.	57.	*	*
UHC	- lb/h	7.	7.	7.	*	*
PART	- lb/h	14.	11.	10.	*	*
		9.0	9.0	9.0	9.0	9.0

EXHAUST ANALYSIS % VOL.

ARGON	0.90	0.90	0.89	0.90	0.90
NITROGEN	74.76	74.67	74.72	74.91	75.49
OXYGEN	12.67	12.43	12.57	13.11	14.76
CARBON DIOXIDE	3.78	3.89	3.83	3.58	2.82
WATER	7.89	8.11	7.99	7.50	6.03

SITE CONDITIONS

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	70
FUEL TYPE	-	CUST GAS
FUEL LHV	- Btu/lb	20790
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
 NOX EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
 NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(1).
 NOX LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE
 SPEEDTRONIC CONTROL SYSTEM.

* DATA CURRENTLY NOT AVAILABLE

IPS-8585
JAH 6-9-92

ACK & VEATCH - FLORIDA POWER *****

ESTIMATED PERFORMANCE - PG7221(PA) -----

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	95	95	95	95	95
AMBIENT RELATIVE HUMID	- %	48	48	48	48	48
OUTPUT	- kW	144200.	115600.	86000.	57100.	29400.
HEAT RATE (LHV)	- Btu/kWh	10630.	11450.	13040.	15670.	21230.
HEAT CONS. (LHV) X10-6	- Btu/h	1532.8	1323.6	1121.4	894.8	624.2
EXHAUST FLOW X10-3	- lb/h	3212.0	2699.0	2376.0	2027.0	1766.0
EXHAUST TEMP	- Deg F.	1124.	1183.	1200.	1200.	1142.
EXHAUST HEAT X10-6	- Btu/h	887.8	800.2	721.8	618.1	498.6
WATER FLOW	- lb/h	95660.	79160.	63000.	46030.	0.

NOX	- ppmvd @ 15% O2	42.	42.	42.	42.	203.
NOX AS NO2	- lb/h	271.	232.	195.	155.	515.
CO	- ppmvd	30.	30.	50.	80.	*
CO	- lb/h	84.	70.	103.	142.	*
UHC	- ppmvv	7.	10.	20.	40.	*
UHC	- lb/h	13.	16.	26.	46.	*
SO2	- ppmvv	11.	11.	11.	10.	8.
SO2	- lb/h	79.	68.	57.	46.	32.
SO3	- ppmvv	1.	1.	0.	1.	1.
SO3	- lb/h	5.	4.	4.	3.	2.
SULFUR MIST	- lb/h	8.	7.	6.	5.	3.
PART	- lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL. -----

ARGON	0.84	0.85	0.84	0.86	0.90
NITROGEN	70.35	70.36	70.76	71.35	74.42
OXYGEN	11.03	10.87	11.33	12.01	14.23
CARBON DIOXIDE	5.12	5.22	5.00	4.65	3.75
WATER	12.66	12.70	12.07	11.13	6.70

SITE CONDITIONS *****

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	48
FUEL TYPE	-	DISTILLATE
FUEL LHV	- Btu/lb	18550
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
NOX EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335(a)(1)(i).
NOX LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE SPEEDTRONIC CONTROL SYSTEM.

DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS.
FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOX VALUE.
SULFUR EMISSIONS BASED ON .05 WTX SULFUR CONTENT IN THE FUEL.

* DATA CURRENTLY NOT AVAILABLE

13.23 DSV FWR DIV
 SLACK & VEATCH - FLORIDA POWER

ESTIMATED PERFORMANCE - PG7221(PA)

LOAD CONDITION		BASE	80%	60%	40%	20%
AMBIENT TEMP.	- Deg F.	40	40	40	40	40
AMBIENT RELATIVE HUMID	- %	70	70	70	70	70
OUTPUT	- kW	178200.	143200.	106900.	70300.	35800.
HEAT RATE (LHV)	- Btu/kWh	10100.	10860.	12270.	14580.	18880.
HEAT CONS. (LHV)	X10-6 - Btu/h	1799.8	1555.2	1311.7	1027.9	675.9
EXHAUST FLOW	X10-3 - lb/h	3652.0	3028.0	2551.0	2152.0	2027.0
EXHAUST TEMP	- Deg F.	1071.	1142.	1200.	1200.	1027.
EXHAUST HEAT	X10-6 - Btu/h	997.5	900.1	809.4	684.5	527.0
WATER FLOW	- lb/h	129530.	109860.	88920.	63480.	0.

NOX	- ppmvd @ 15% O2	42.	42.	42.	42.	240.
NOX AS NO2	- lb/h	318.	273.	228.	177.	660.
CO	- ppmvd	30.	30.	50.	80.	*
CO	- lb/h	96.	79.	112.	152.	*
UHC	- ppmvv	7.	10.	20.	40.	*
UHC	- lb/h	15.	17.	29.	51.	*
SO2	- ppmvv	11.	12.	12.	11.	8.
SO2	- lb/h	92.	80.	67.	53.	35.
SO3	- ppmvv	1.	1.	1.	1.	0.
SO3	- lb/h	6.	5.	5.	3.	2.
SULFUR MIST	- lb/h	10.	8.	7.	6.	4.
PART	- lb/h	17.0	17.0	17.0	17.0	17.0

EXHAUST ANALYSIS % VOL.

ARGON	0.87	0.86	0.86	0.87	0.92
NITROGEN	71.09	70.92	71.10	71.91	76.13
OXYGEN	10.93	10.61	10.72	11.56	14.96
CARBON DIOXIDE	5.31	5.49	5.45	5.04	3.57
WATER	11.81	12.13	11.88	10.62	4.42

SITE CONDITIONS

ELEVATION	- ft.	163
SITE PRESSURE	- psia	14.62
INLET LOSS	- in. Water	3.5
EXHAUST LOSS	- in. Water	12
RELATIVE HUMIDITY	- %	70
FUEL TYPE	-	DISTILLATE
FUEL LHV	- Btu/lb	18550
APPLICATION	-	317S HYDROGEN COOLED GENERATOR
COMBUSTION SYSTEM	-	DRY LOW NOX

EMISSION INFORMATION BASED ON GE RECOMMENDED MEASUREMENT METHODS.
 NOX EMISSIONS ARE CORRECTED TO 15% O2 WITHOUT HEAT RATE CORRECTION AND ARE
 NOT CORRECTED TO ISO REFERENCE CONDITIONS PER 40CFR 60.335() (1).
 NOX LEVELS SHOWN WILL BE CONTROLLED BY ALGORITHMS WITHIN THE
 SPEEDTRONIC CONTROL SYSTEM.

DISTILLATE FUEL IS ASSUMED TO HAVE .015% FUEL BOUND NITROGEN, OR LESS.
 FBN AMOUNTS GREATER THAN .015% WILL ADD TO THE REPORTED NOX VALUE.
 SULFUR EMISSIONS BASED ON .05 WTX SULFUR CONTENT IN THE FUEL.

* DATA CURRENTLY NOT AVAILABLE

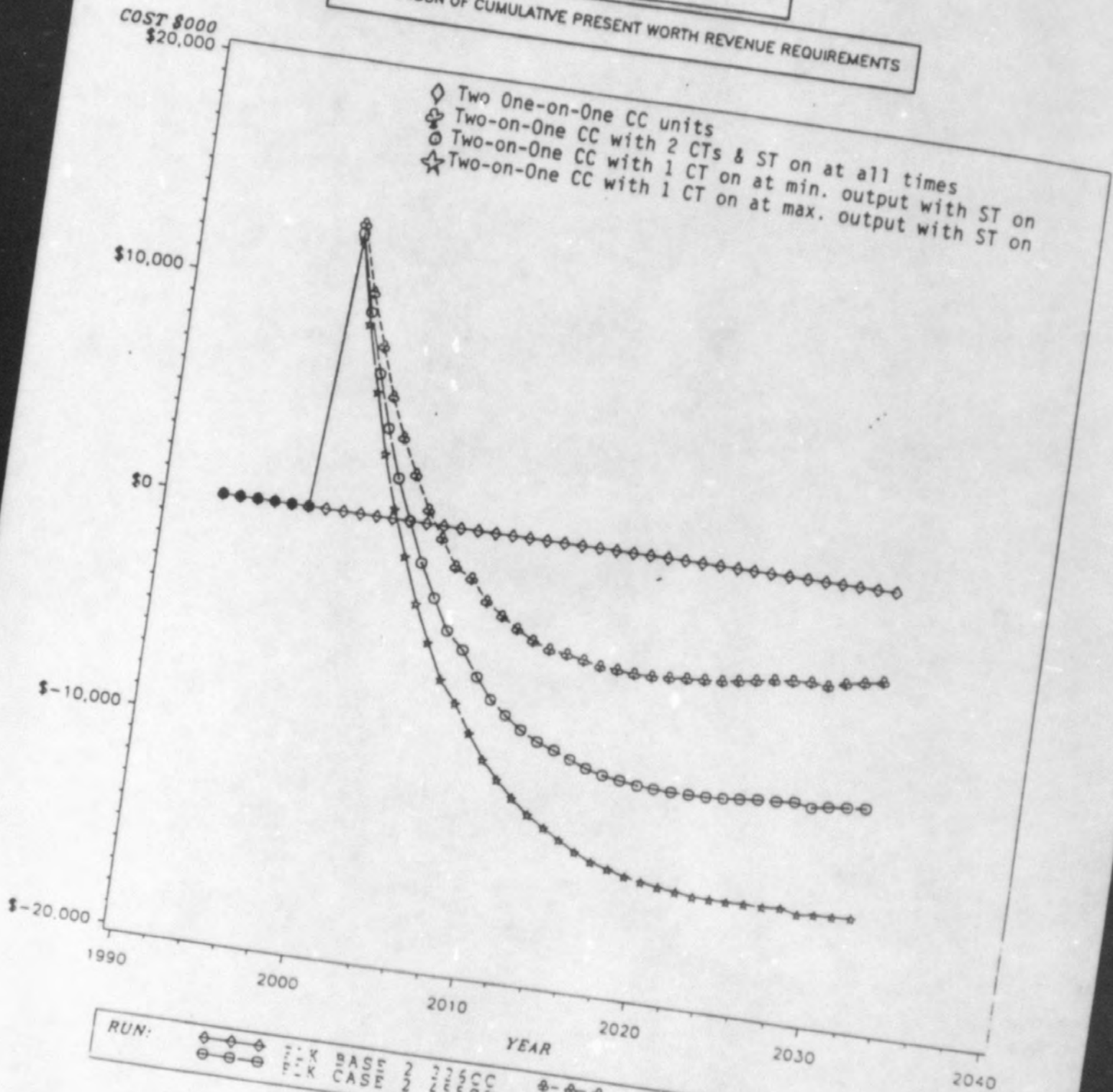
IPS-8585
 JAH 7-22-92

STUDY RESULTS

POLK COUNTY ALTERNATIVES

2 226MW CC vs 1 455MW CC

COMPARISON OF CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS



RUN: POLK BASE 2 226MW CC CASE 2 = PS940325 POLK CASE 1 = PS940324

BASE = PS940323 CASE 1 = PS940326

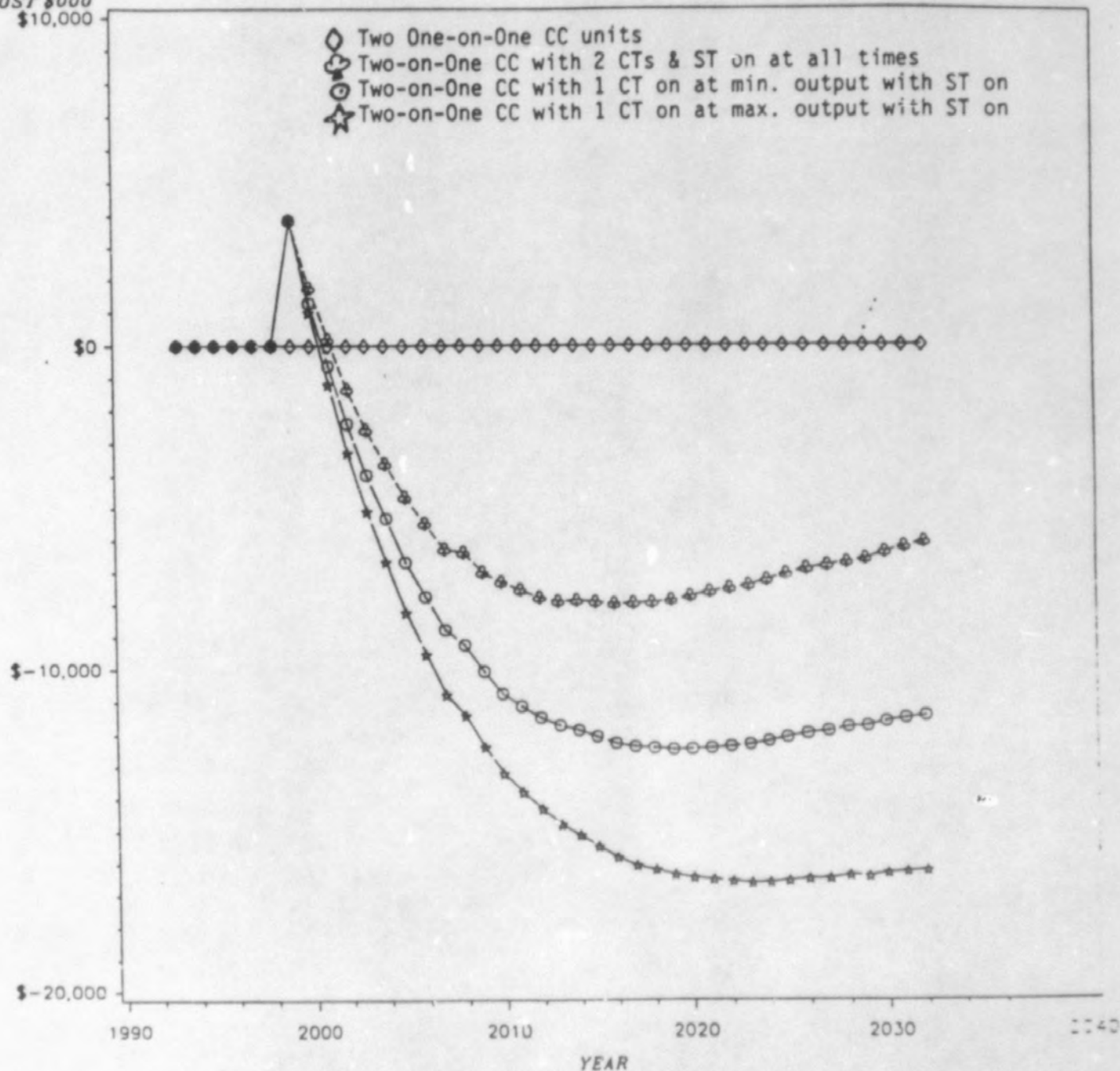
STUDY RESULTS

POLK COUNTY ALTERNATIVES

2 226MW CC vs 1 455MW CC DELAY 2nd HALF 1 YEAR

COMPARISON OF CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS

COST \$000
\$10,000



RUN:

PLK BASE

PLK CASE

226CC

455CC

PLK

PLK

PLK

PLK

BASE = PS940323 CASE 4 = PS940327
CASE 5 = PS940328 CASE 6 = PS940329

07/26/94

16:48

B&V PWR DIV

NO. 100

P001



BLACK & VEATCH

8400 Ward Parkway, P.O. Box No. 8405, Kansas City, Missouri 64114, (913) 339-2000

FAX NUMBERS: 913-339-2934 913-339-2936 913-339-2939

FACSIMILE TRANSMISSION

TO: Randy LehnhoffCOMPANY: Florida Power CorporationFAX NUMBER: (813) 866-4994TELEPHONE NUMBER: (813) 866-4033FROM: Mike EddingtonEXTENSION: 2056LOCATION: P4B4B&V PROJECT: 18875B&V PHASE: 040

B&V FILE: _____

DATE: July 20, 1994NUMBER OF PAGES, INCLUDING THIS COVER SHEET: 2

NOTE TO RECEIVING OPERATOR
In the event of incomplete transmission, please call (913) 339-7218.

TRANSMITTAL DATE/TIME: _____

OPERATOR'S INITIALS: _____

SUBJECT: Polk County Unit Data Request

MESSAGE: Please find attached a summary table of the performance at 62 F and Base Load while burning natural gas.

Please call me at 913-339-2056 if you have any questions.

cc: CJS
SMC
RVN

07/20/94

16:48

B&V PWR DIV

NO. 100

P002

07/20/94

Florida Power Corporation
Polk County Project

2 on 1 7FA Units**ESTIMATED NEW AND CLEAN PERFORMANCE**

Base Load
Natural Gas
62 F., 75% RH

No. 1 Combustion Turbine Output, kW	152,930
No. 2 Combustion Turbine Output, kW	152,930
No. 1 Steam Turbine Output, kW	102,110
No. 2 Steam Turbine Output, kW	N/A
Total Gross Plant Output, kW	467,970
Auxiliary Power, kW	10,760
Total Net Plant Output, kW	457,210
CT Heat Consumption, MBtu/h (HHV)	3,307.5
CT Heat Consumption, MBtu/h (LHV)	2,980.6
CTG Gross Heat Rate, Btu/kWh, (LHV)	8,745
Net Plant Heat Rate, Btu/kWh (HHV)	7,234
Net Plant Heat Rate, Btu/kWh (LHV)	6,519

POLK COUNTY STUDY

1ST UNIT TIMING

COMPARISON OF CUMULATIVE PRESENT WORTH REVENUE REQUIREMENTS

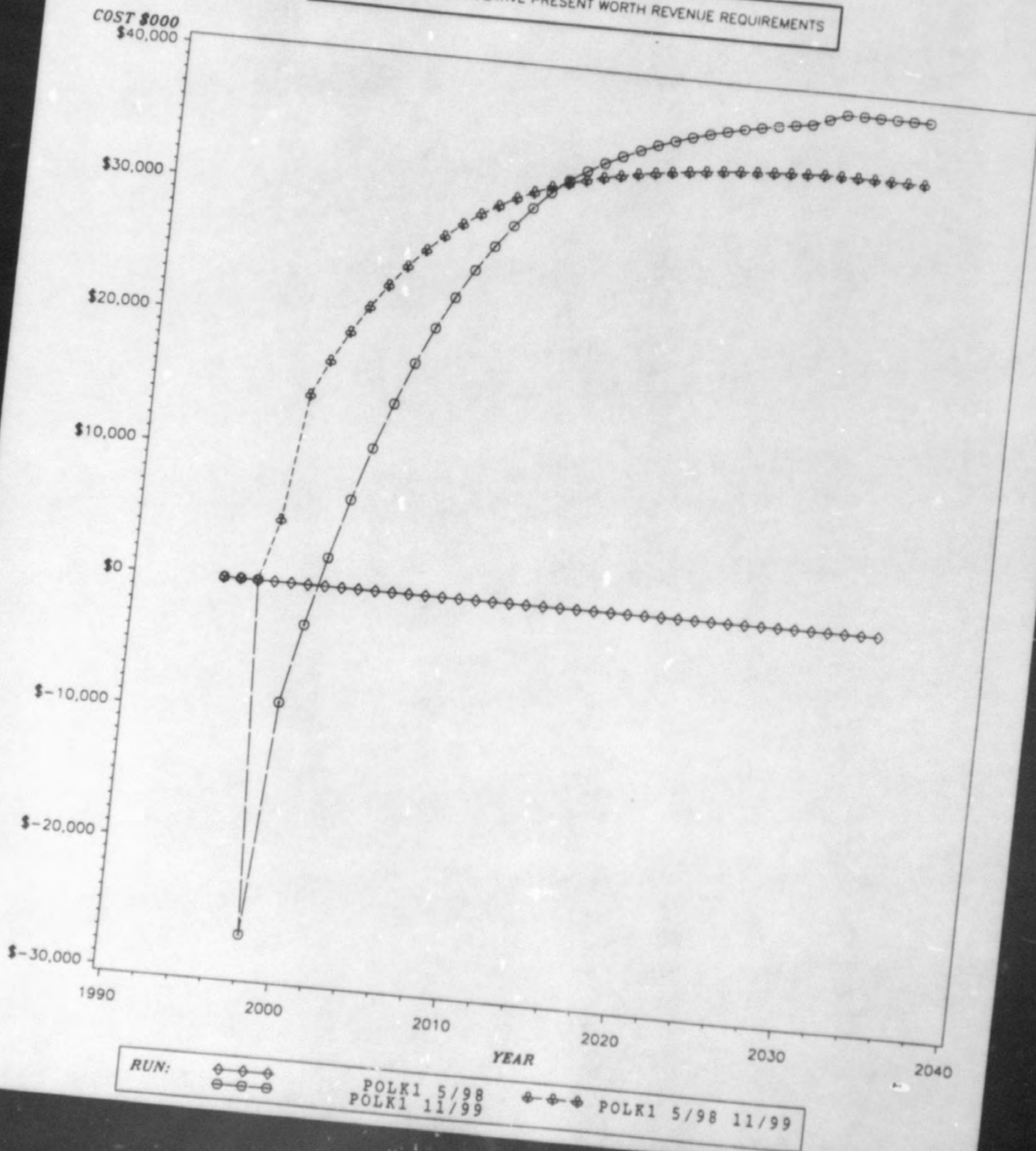


EXHIBIT E

DOCKET NO.:

960409-EI

WITNESS:

NIEKUM AND MAJORS

DESCRIPTION:

**FLORIDA POWER CORPORTION POLK COUNTY
SITE DEVELOPMENT COSTS (MAY 31, 1996)**

**FLORIDA POWER CORPORATION
POLK COUNTY COMBINED CYCLE PROJECT
ANALYSIS OF TOTAL SITE DEVELOPMENT COSTS
In Thousands Including AFUDC**

	(A)	(B)	(C)
DESCRIPTION OF COST	CURRENT PROJECT ESTIMATE (Includes Actuals Through Apr 96)	TOTAL SITE DEVELOPMENT (Docket No. 910759-EI, Exhibit 101, Table 24.1)	VARIANCE (A - B)
1 <u>SITE SELECTION 1988 - 1989 :</u>	\$ 2,230	\$ 1,669	\$ 561
2 This approximate two year effort focused on			
3 identifying and evaluating feasible generation			
4 sites throughout Florida and ultimately selecting			
5 the Polk County site.			
6	25,341	27,510	(2,169)
7 <u>SITE CERTIFICATION, LICENSING 1990-1994:</u>			
8 This 3 1/2 year effort focused on acquiring Need			
9 Determination and Site Certification for Polk			
10 County. Numerous studies and evaluations were			
11 performed to determine generation need and			
12 environmental impacts associated with the			
13 ultimate build-out of the site. The capability of the			
14 site to support 3,000 MW of generation using a			
15 combination of natural gas, oil and coal fuel			
16 mixes was successfully demonstrated.			
17	83,755	85,320	(1,565)
18 <u>LAND & SITE DEVELOPMENT :</u>			
19 Land purchases include the acquisition of 8,200			
20 acres from three separate property owners; IMC,			
21 Estech and USAC. Site development costs			
22 include primarily reclamation earthwork, clay			
23 consolidation, solid waste disposal, development			
24 of ponds & dams, and environmental services.			
25 These costs include \$3.9 Million for IMC to			
26 relocate a clay slurry pipeline to preserve the			
27 borrow area fill quality.			
28	\$ 111,326	\$ 114,499	(3,173)
29 TOTAL SITE DEVELOPMENT			

H:\NLHF\FILES\FORCAST\POLK\SITDPSC1.XLS
5/31/96 8:37

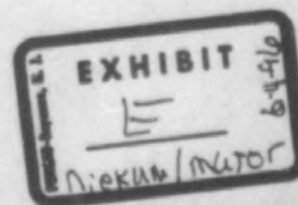


EXHIBIT F

DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJORS

DESCRIPTION: FLORIDA POWER CORPORTION POLK COUNTY
SITE PROJECT FORECAST SUMMARY
(JUNE 1996)

Forecast Summary

POLK COUNTY PROJECT WFM10		TOTAL	ACTUAL	COST THRU	TOTAL	1996-2000	WORK	VARIANCE	VARIANCE		
05-Jun-96 10:50:23 AM		2000	4/96	4/96	ESTIMATE	FIVE YEAR PLAN	ORDER	ACTUAL + FCAST vs 5 YR PLAN	ACTUAL + FCAST vs WORK ORDER	CONTRACT	VENDOR
SECTION 1: SITE SELECTION											
RPP001	SITE SELECTION EXPENSE			1,669,180	1,669,180	1,669,180	1,669,180	-	-		
SECTION 2: SITE CERTIFICATION/LICENSING											
RPP002	SITE CERTIFICATION					1,948,447	1,948,447	-	0		
RPP02001	FPC SALARIES & EXPENSES			1,948,447	1,948,447	1,112,304	1,112,134	-	170		
RPP02001001	NEED DETERMINATION EXPENSES			1,112,304	1,112,304	3,060,750	3,060,581	-	170		
	SUB-TOTAL (FPC ENGR)			3,060,750	3,060,750			-	-		
RPP02002	ENGR SUPPORT FOR E & L					1,296,172	1,296,172	-	-	Various	Legal Department
RPP02002001	LEGAL SERVICES			1,296,172	1,296,172	800,000	800,000	-	0	PRO-01256	Black & Veatch
RPP02002003	BLACK & VEATCH PRO-01256			800,000	800,000	85,125	85,125	0	0		
RPP02002004	OUTSIDE PROFESSIONAL SERV			85,125	85,125	2,181,297	2,181,297	-	-		
	SUB-TOTAL (OUTSIDE ENGR)			2,181,297	2,181,297	13,726,970	13,726,970	-	-		
RPP02003	EBASCO ENVIR SERV CONTRACT			13,726,970	13,726,970	18,969,017	18,968,848	-	170		
	TOTAL SECTION 2			18,969,017	18,969,017						
SECTION 3: LAND & RECLAMATION											
RPP02001	FPC SALARIES & EXPENSES	101,654		1,404,566	1,504,566	1,758,258	1,696,908	(253,692)	(192,342)		
RPP02001003	FIELD OFFICE SET-UP & EXPENSES	1,542		473,407	482,013	483,934	483,934	(1,922)	(1,922)	LCO0151	Johnson Brothers Corp
RPP02002005	INDEPENDENT EQUIPMENT REVIEW			78,775	78,775	80,000	78,775	(1,226)	-	G5000755	MPR Associates
RPP02002001	LEGAL SERVICES	15,741		236,588	269,777	238,113	261,169	31,664	8,607	PRO-01256	Black & Veatch
RPP02002003	BLACK & VEATCH PRO-01256			537,930	537,930	537,930	537,929	(0)	1	PRO-01012	Foster Wheeler
RPP02003	EBASCO ENVIR SERV CONTRACT	156,665		3,875,260	6,507,186	7,273,030	7,273,030	(765,644)	(765,644)		
RPP010100001	IMC PROPERTIES(5111 58 acres)			5,619,321	5,619,321	5,619,321	5,619,321	-	0		
RPP010100002	ESTECH PROPERTIES(1988 180 acres)			3,341,926	3,306,989	3,297,364	3,297,364	9,625	9,625		
RPP010100003	CSX ABANDONED RR ROW(14.38 acre)			14,297	14,297	14,297	14,297	-	-		
	USAC (1 acre + mod real plan)			6,000	6,000	6,000	6,000	-	-		AGRIC-O
	USAC Mitigation				24,000	24,000	24,000	-	-		
	USAC PROPERTIES(80 85 acres)				72,855	72,855	72,855	-	-		
	SUB-TOTAL (LAND)			8,981,544	9,043,462	9,033,837	9,033,837	9,625	9,625	PRO-01367	IMC Chemical
RPP120290786	IMC CLAY PIPELINE			3,900,000	3,900,000	3,900,000	3,900,000	-	-	G5000504	SEMCO
RPP120290786	SEMCO SPILLWAYS ON N-15			28,550	28,550	28,550	28,550	-	-	G4000532	ARMAC
RPP120290786	ARMAC GEOTECHNICAL SERVICES			7,997	31,997	32,000	31,997	(3)	(0)	G4000481	Seminole Gridding
RPP120290786	EMBANKMENT SLOPE MOWING			9,902	51,902	55,568	52,068	(3,666)	(166)	LCO0155	Ardamco & Assoc
RPP120290786	OBSERVATION WELLS			8,612	8,612	8,612	8,612	-	-		Horizontal Tech
RPP120290786	SOCK DRAINS			5,885	5,885	3,035	5,884	2,850	1	G5000628	Southeast Industrial
RPP120290786	PUMP UNSUITABLES			8,685	8,685		65,000	8,685	(56,315)	G5000660	Kimmins Contracting
RPP120290786	CSX CULVERT CROSSING			161,446	161,446	160,802	160,802	644	644		
RPP120290786	PAY ON APPROVALS	891		49,985	49,985	13,858	18,994	36,127	30,991	G4000409	Brown & Root
	EARTHWORK - B&R	1,741,650		20,360,012	20,397,001	27,597,000	27,597,000	(1,199,999)	(1,199,999)	G4000409	Brown & Root
	B&R Earthwork - Non SBO Intake			13,068	496,264			496,264	496,264		
	TOTAL EARTHWORK	1,741,650		20,373,080	26,893,265	27,597,000	27,597,000	(703,735)	(703,735)	G5000646	Wilkinson Hydrology
	CLAY CONSOLIDATION	37,742		315,257	1,105,617	1,105,632	1,105,632	(15)	(15)		
	TOTAL CLAY CONSOLIDATION	37,742		315,257	1,105,617			-	-		
	TOTAL SAND TAIL PUMPING				1,304,000	2,408,000	1,454,000	(1,104,000)	(150,000)		
	SA & SOLID WASTE DISPOSAL AREA				4,312,000	4,312,000	4,312,000	-	-		
	SA & BRINE POND							-	-		
	WATER CROPPING					186,499	186,499	300,000	300,000		
	N-15				486,499	195,900	195,900	-	-		
	PHOSPHORUS				161,200	161,200	161,200	-	-		
	P-2				161,200	195,900	195,900	-	-		
	P-3				195,900	739,499	739,499	300,000	300,000		
	TOTAL WATER CROPPING				1,039,499	158,407	158,407	(38,570)	(38,570)	G4000489 & 9 Estech, Inc	
	ESTECH			119,837	119,837						

EXHIBIT
4-11
13-10-96

Forecast Summary

POLK COUNTY PROJECT WF0410						1996-2000		VARIANCE	VARIANCE		
05-Jun-96		TOTAL	ACTUAL	COST THRU	TOTAL	FIVE YEAR	WORK	ACTUAL + FCAST	ACTUAL + FCAST		
10:50:23 AM		2000	4/96	4/96	ESTIMATE	PLAN	ORDER	vs 5 YR PLAN	vs WORK ORDER	CONTRACT	VENDOR
	SA 10 McCULLOUGH CREEK				709,000	309,000	279,000	400,000	430,000		
	SUB-TOTAL (RECLAMATION)	1,779,392	20,808,174	35,483,218		36,629,538	35,645,538	(1,146,320)	(162,320)		
	COE (MITIGATION)										
	PROPERTY TAXES		74,971	299,971				299,971	299,971		
RPP170545215	BARTON PIPELINE	380,506	1,441,213	1,725,000		1,783,831	1,783,831	(58,831)	(58,831)	G4000156	City of Bartow
	EFFLUENT PIPELINE OURS			399,834				399,834	399,834	G60001058	HALL CONTRACTORS
	BARTON LOAN										
	WILDLIFE CORR (425 ACRE X \$900)		397,548	397,548		397,548	397,548				
RPP170420222	PERMANENT ROADS		2,425	2,425		2,425	2,424		1		
RPP062004	SITE SECURITY	9,316	166,810	186,714		214,020	214,020	(27,307)	(27,306)		
	CONTINGENCY (RECLAM EA)			1,521,353		2,587,423	2,587,423	(1,066,070)	(1,066,070)		
	TOTAL SECTION 3	2,445,706	42,660,271	62,686,830		65,222,311	64,268,273	(2,535,481)	(1,581,443)		
	SECTION 4 ENGR & CONSTR (INCL CONT)										
	TOTAL SECTION 4		244,495	3,344,891	158,227,454	163,527,333	168,342,014	(10,634,132)	(15,448,813)		
	TOTAL BASE COST		2,690,201	66,643,360	241,552,481	249,387,842	253,248,315	(7,835,360)	(11,695,834)		
	ESCALATION										
	GAC LOADING		1,658	98,765	274,309	379,296	377,714	(104,987)	(103,405)		
	TOTAL ESCALATED COST W/O AFUDC		2,691,859	66,742,125	241,826,790	249,767,137	253,626,029	(7,940,347)	(11,799,239)		
	AFUDC CHARGE		418,722	10,280,406	39,150,333	43,289,696	43,166,550	(4,139,363)	(4,015,217)		
	TOTAL PROJECT COST		3,110,581	77,022,531	280,977,123	293,056,833	296,792,579	(12,079,710)	(15,815,456)		

EXHIBIT G

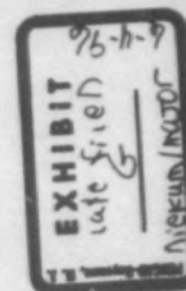
DOCKET NO.: 960409-EI

WITNESS: NIEKUM AND MAJORS

DESCRIPTION: FLORIDA POWER CORPORTION POLK COUNTY
PROJECTED COST IN CENTS/KWH

Table 1
 FLORIDA POWER CORPORATION
 Polk Power Block 1 - Combined Cycle Units

1	2	3	4	5	6	7	8	9	10	11
Year	Fuel Cost	Gen.	O&M		Fuel		Capital		Total	
	\$/MMBTU	GWH	(\$000)	c/kwh	(\$000)	c/kwh	(\$000)	c/kwh	(\$000)	c/kwh
1999	\$2.59	3,908	\$4,368	0.112	70,349	1.800	56,555	1.447	131,272	3.359
2000	\$2.65	3,908	\$5,146	0.132	71,864	1.839	54,937	1.406	131,947	3.376
2001	\$2.70	3,908	\$6,717	0.172	73,379	1.877	52,865	1.353	132,960	3.402
2002	\$2.76	3,908	\$5,549	0.142	76,222	1.950	50,874	1.302	132,646	3.394
2003	\$2.87	3,908	\$5,538	0.142	79,066	2.023	48,960	1.253	133,564	3.417
2004	\$2.98	3,908	\$7,121	0.182	81,936	2.096	47,116	1.206	136,173	3.484
2005	\$3.08	3,908	\$5,799	0.148	84,807	2.170	45,337	1.160	135,942	3.478
2006	\$3.19	3,908	\$7,129	0.182	86,348	2.209	43,618	1.116	137,095	3.508
2007	\$3.25	3,908	\$6,239	0.160	87,949	2.250	41,944	1.073	136,131	3.483
2008	\$3.31	3,908	\$6,405	0.164	89,578	2.292	40,284	1.031	136,267	3.487
2009	\$3.37	3,908	\$6,590	0.169	91,238	2.334	38,624	0.988	136,452	3.491
2010	\$3.43	3,908	\$6,800	0.174	92,929	2.378	36,964	0.946	136,694	3.497
2011	\$3.50	3,908	\$7,020	0.180	94,652	2.422	35,304	0.903	136,976	3.505
2012	\$3.56	3,908	\$7,240	0.185	96,406	2.467	33,644	0.861	137,291	3.513
2013	\$3.63	3,908	\$7,470	0.191	98,194	2.512	31,985	0.818	137,649	3.522
2014	\$3.69	3,908	\$7,710	0.197	100,015	2.559	30,325	0.776	138,050	3.532
2015	\$3.76	3,908	\$7,960	0.204	101,870	2.606	28,665	0.733	138,495	3.544
2016	\$3.83	3,908	\$8,210	0.210	103,761	2.655	27,005	0.691	138,976	3.556
2017	\$3.90	3,908	\$8,470	0.217	105,687	2.704	25,345	0.648	139,502	3.569
2018	\$3.98	3,908	\$8,740	0.224	107,649	2.754	23,686	0.606	140,075	3.584
2019	\$4.05	3,908	\$9,020	0.231	109,676	2.806	22,068	0.565	140,764	3.602
2020	\$4.13	3,908	\$9,310	0.238	111,740	2.859	20,793	0.532	141,843	3.629
2021	\$4.20	3,908	\$9,610	0.246	113,844	2.913	19,816	0.507	143,270	3.666
2022	\$4.28	3,908	\$9,920	0.254	115,987	2.968	18,840	0.482	144,747	3.704
2023	\$4.36	3,908	\$10,240	0.262	118,171	3.024	17,863	0.457	146,274	3.743



FLORIDA POWER CORPORATION
Polk Power Block 1 - Combined Cycle Units

Assumptions

7	Plant Size (MW)	507
8	Inservice Date	January 1999
9	Inservice Generation and Site Investment with AFUDC	\$280,977,000
10	Average capacity factor	88%
11	Heat Rate (Btu/kWh)	6,800
12	Fuel Cost	Fuel Forecast 9601
13	O&M Cost per kWh	See Table 1
14	Annual Revenue Requirements per kWh	See Table 1
15	Property tax millage - \$/1000	\$18.47
16	Book life, years	25
17	Return on Debt	7.5%
18	Return on Equity	12.0%
19	Capital Ratio for Debt	40.0%
20	Capital Ratio for Equity	60.0%
21	Composite Cost of Capital	10.20%
22	General Inflation Rate	3.2%

**COMPOSITE
EXHIBIT H**

DOCKET NO.:

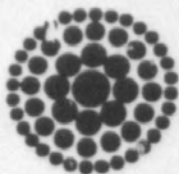
960409-EI

WITNESS:

NIEKUM AND MAJOR

DESCRIPTION:

**FLORIDA POWER CORPORTION COMPOSITE OF
FUEL FORECASTS (1991 - 1996)**



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department

OFFICE

MAC

C2B

231-4532

TELEPHONE

SUBJECT: **Fuel Cost Projection (FCP 9602)**

TO: **Mr. M. D. Rib**
Mr. K. H. Wieland

DATE: **May 3, 1996**

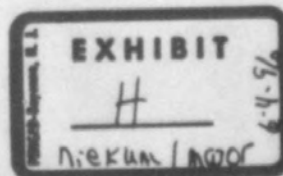
Please find attached FCP 9602. This updates the short term forecast prices for fuel for the October 1996 - March 1997 Fuel Adjustment.

If you have any questions or require additional information, please advise.

Dale Williams
Dale Williams

Attachment:

xc: J. W. Agee
G. A. Aldazabal
L. D. Brousseau
M. L. Daley
R. D. Dolan
D. G. Edwards
J. R. Lindquist
G. E. Matzke
P. Z. McGovern
W. C. Micklon
R. D. Niekum
D. M. OShea
G. L. Peterson
J. M. Quinlivan
J. R. Rocha
L. G. Schuster
J. L. Simpson
P. E. Toomey
T. L. Waldmann
L. A. Welch
File
Forecast Book





ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

May 2, 1996

Mr. Dale D. Williams
Principal Fuel Buyer
Fuel and Special Projects—C2B
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Dear Dale:

Attached are the *May 1996 through December 1997 Coal Price Forecasts* for Crystal River Units 1 and 2 (Attachment A), Crystal River Units 4 and 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your October 1996-March 1997 fuel adjustment filing. We have based our calculations on the latest financial estimates for 1996 and 1997 provided by our Accounting Department and the assumptions listed on Appendix I.

If you require additional information, please call me or Donna Davis.

Sincerely,

A handwritten signature in cursive script that reads 'Raynia A. Hemmer'.

Raynia A. Hemmer
Contract Administration Specialist

RAH/ro

Attachments

cc/att: Mr. W. D. Carter
Mr. D. J. Clark, Jr.
Mr. D. G. Edwards
Mrs. D. M. Davis
Mr. S. M. Hopkins

ELECTRIC FUELS CORPORATION
1996 & 1997 COAL PRICE FORECAST
CRYSTAL RIVER 1 & 2

Year/Month	Tons (000)	Btu/Lb	\$/Ton	\$/MBtu	
				Average	Incremental
<u>1996</u>					
May	149	12,781	42.19	1.650	1.640
June	208	12,571	43.17	1.717	1.640
July	198	12,575	43.27	1.720	1.647
August	193	12,577	42.63	1.695	1.640
September	184	12,581	43.32	1.722	1.648
October	198	12,600	42.50	1.687	1.644
November	158	12,594	42.67	1.694	1.659
December	191	12,604	42.36	1.680	1.645
<u>1997</u>					
January	168	12,588	42.61	1.693	1.682
February	168	12,588	42.64	1.694	1.682
March	158	12,594	42.75	1.697	1.684
April	168	12,588	42.66	1.695	1.684
May	188	12,605	42.82	1.699	1.680
June	168	12,588	42.71	1.696	1.684
July	188	12,605	42.74	1.695	1.682
August	168	12,588	42.75	1.698	1.686
September	188	12,605	42.78	1.697	1.682
October	168	12,588	42.91	1.704	1.686
November	188	12,605	42.82	1.698	1.684
December	179	12,594	42.75	1.697	1.684

ELECTRIC FUELS CORPORATION
1996 & 1997 COAL PRICE FORECAST
CRYSTAL RIVER 4 & 5

Year/Month	Tons (000)	Btu/Lb	\$/Ton	\$/MBtu	
				Average	Incremental
<u>1996</u>					
May	320	12,649	50.02	1.977	1.672
June	321	12,589	49.69	1.974	1.675
July	326	12,578	50.21	1.996	1.682
August	331	12,601	49.61	1.969	1.676
September	318	12,588	50.00	1.986	1.683
October	272	12,555	50.49	2.011	1.679
November	282	12,561	50.74	2.020	1.694
December	283	12,556	50.53	2.012	1.730
<u>1997</u>					
January	282	12,542	51.18	2.040	1.777
February	282	12,542	51.18	2.040	1.778
* March	282	12,542	51.24	2.043	1.780
April	282	12,542	51.21	2.042	1.779
May	282	12,542	51.30	2.045	1.775
June	282	12,542	51.25	2.043	1.780
July	282	12,542	51.35	2.047	1.777
August	282	12,542	51.33	2.046	1.782
September	282	12,542	51.38	2.048	1.777
October	292	12,541	51.57	2.056	1.781
November	282	12,542	51.42	2.050	1.780
December	291	12,541	51.43	2.051	1.779

ELECTRIC FUELS CORPORATION
1996 & 1997 COAL PRICE FORECAST
CRYSTAL RIVER 1 & 2 and 4 & 5

Year/Month	Tons (000)	Btu/Lb	\$/Ton	Average \$/MBtu
<u>1996</u>				
May	469	12,691	47.54	1.873
June	529	12,582	47.13	1.873
July	524	12,577	47.59	1.892
August	524	12,592	47.04	1.868
September	502	12,585	47.55	1.889
October	470	12,574	47.12	1.874
November	440	12,573	47.83	1.902
December	474	12,575	47.24	1.878
<u>1997</u>				
January	450	12,559	47.98	1.910
February	450	12,559	47.98	1.910
March	440	12,561	48.18	1.918
April	450	12,559	48.01	1.911
May	470	12,567	47.90	1.906
June	450	12,559	48.05	1.913
July	470	12,567	47.90	1.906
August	450	12,559	48.12	1.916
September	470	12,567	47.94	1.907
October	460	12,558	48.40	1.927
November	470	12,567	47.97	1.909
December	470	12,561	48.12	1.915



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1, 1996—MARCH 31, 1997 PAGE 1 OF 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE. AN INFLATION ASSUMPTION OF 2.5% FOR 1996 AND 1997 (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- TWO NEW CRYSTAL RIVER 1 & 2 RAIL-DELIVERED COAL CONTRACTS EFFECTIVE JANUARY 1, 1996, TOTALLING 800,000 TONS HAVE REPLACED CONTRACTS EXPIRING IN 1995. TWO NEW ONE-YEAR CRYSTAL RIVER 4 & 5 RAIL-DELIVERED COAL CONTRACTS TOTALLING 500,000 TONS EFFECTIVE OCTOBER 1, 1995, REPLACED THE TONNAGE REDUCTION ON AN EXISTING CONTRACT RESULTING FROM A MARKET REOPENER IN 1995. NO MARKET REOPENERS ARE APPLICABLE IN 1996 OR 1997.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S AND HILL & ASSOCIATES' (EFC'S COAL INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL MARKET INFORMATION.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT AN INFLATION ASSUMPTION OF 2.5% (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT TWO SETS OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF DECEMBER 1, 1996, AND 1997, AT A COST PER SET OF APPROXIMATELY \$5.3 AND \$5.5 MILLION, RESPECTIVELY.
- 1996 AND 1997 WATER FREIGHT IS ESTIMATED AT THE CURRENT MARKET RATE ESCALATED AT THE FORECASTED CHANGE OF THE INDIVIDUAL INDICES, IN ACCORDANCE WITH THE WATERBORNE COMPONENT PROVISIONS.



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1 1996—MARCH 31, 1997 PAGE 2 OF 2

GENERAL ADMINISTRATION

- COSTS ARE BASED ON THE 1996 ANNUAL PLAN.
- 36 PERCENT EFFECTIVE TAX RATE ASSUMED FOR INCOME TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON FPC'S TOTAL REQUIREMENT OF 5,800,000 TONS FOR 1996 AND FPC'S PROMOD ESTIMATE OF 5,500,000 FOR 1997.

FUELS SUPPLY DEPARTMENT

FCP 9602

NUCLEAR FUEL

CYCLE

DATE

\$/MMBTU⁽¹⁾

11

05/96 - 03/98

.326

⁽¹⁾ Does not include spent fuel disposal or enrichment plant decommissioning charges

FUELS SUPPLY DEPARTMENT
FCP 9602
FUEL OIL
Delivered to Florida - West Coast

\$/MMBtu

	<u>#6 Fuel Oil</u>			<u>#2 Fuel Oil</u>
	1.0%	1.5%	2.5%	0.5%
May 96	3.05	2.90	2.65	4.50
June 96	2.90	2.75	2.50	4.25
July - Dec 96	2.65	2.55	2.40	4.20
Jan - Mar 97	2.75	2.65	2.50	4.50
Apr - Dec 97	2.60	2.50	2.30	4.00

Additional Transportation Cost

\$/MMBtu

1996 - 1997

#6 Fuel Oil

Suwannee	2.50%	.65
	1.00%	1.10

#2 Fuel Oil

Anclote	.12
Avon Park	.20
Bartow/Bayboro	.16
Crystal River	.21
DeBary	.24
Higgins	.09
Intercession City	.19
Port St. Joe	.24
Rio Pinar	.22
Suwannee	.21
Turner	.24

April 29, 1996.

FCP9602.DDW.1

FUELS SUPPLY DEPARTMENT

FCP 9602

NATURAL GAS
\$/MMBTU

Supply Cost

May - Dec 96	2.30
Jan - Mar 97	2.10
Apr - Sep 97	1.80
Oct - Dec 97	1.90

Additional Transportation Cost

<u>Firm</u> ⁽¹⁾	<u>Demand Charge</u>	<u>Variable Charge</u> ⁽³⁾⁽⁴⁾
FGT FTS-2	.76	.14
FGT FTS-1	.44	.14
Suwannee	.51	.23

<u>Interruptible</u>	<u>Variable Charge</u> ⁽²⁾⁽³⁾⁽⁴⁾
FGT	.45
Suwannee	.55

- (1) See attached table for FT quantities
 (2) Add \$0.40/MMBtu for Premium Daily Interruptible Transportation
 (3) Add \$0.10/MMBtu to University of Florida for GRU transportation
 (4) Add \$0.25/MMBtu to Intercession City for KUA/FGU transportation

FCP9602.DDW.1

April 29, 1996

FUELS SUPPLY DEPARTMENT

FCP 9602

NATURAL GAS

Interruptible Transportation⁽¹⁾

Estimates of Availability

MMBTU

FLORIDA GAS TRANSMISSION

Bartow Max Hour ⁽²⁾	2,050/hour
Higgins Max Hour ⁽²⁾	2,100/hour
Avon Park Max Hour	650/hour
Intercession City Max Hour	6,000/hour
Total average pipeline availability:	
Daily	30,000/day
Monthly ⁽³⁾	35,000/day
Premium Daily	25,000/day

SOUTHERN/SOUTH GEORGIA NATURAL GAS

Suwannee Max Hour	1,500/hour
-------------------	------------

Total average pipeline availability:	
Jun, Jul, Aug, Dec, Jan, Feb:	6,000/day
Mar, Apr, May, Sep, Oct, Nov:	20,000/day

- (1) This may be in the form of Interruptible Tariff Transportation or Temporary Released Firm capacity.
- (2) Higgins and Bartow combined can't exceed 2,100/hr
- (3) Monthly interruptible requires FPC to take the volume everyday of an entire month

FCP9602.DDW.1

April 29, 1996.

FPC Firm Transportation Schedule
MMBtu/Day

<u>Month</u>	<u>FGT FTS-1</u>	<u>FGT FTS-2</u>	<u>Suwannee</u>
			6,000
		0	6,000
May 96	13,300	0	6,000
Jun 96	13,300	0	6,000
Jul 96	13,300	0	6,000
Aug 96	13,300	0	6,000
Sep 96	14,300	1,000	6,000
Oct 96	19,515	4,000	6,000
Nov 96	19,515	4,000	0
Dec 96	19,515	4,000	0
Jan 97	19,515	4,000	0
Feb 97	19,515	4,000	0
Mar 97	19,515	4,000	0
Apr 97	14,300	1,000	0
May 97	14,300	1,000	0
Jun 97	14,300	1,000	0
Jul 97	14,300	1,000	0
Aug 97	14,300	1,000	0
Sep 97	14,300	1,000	0
Oct 97	19,515	4,000	0
Nov 97	20,765	7,750	
Dec 97			

FCP9602.DDW.1

April 29, 1996

DEPARTMENT

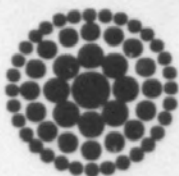
DEPARTMENT
FCP 9602

FUEL INVENTORY TARGET LEVELS ⁽¹⁾

	INVENTORY W/O TANK BOTTOMS	TANK BOTTOMS	TOTAL INVENTORY
RESIDUAL OIL (#6) BBLs			
		138,346	438,346
Anclote & Bartow South	300,000	63,214	213,214
Bartow & Bartow North	150,000	12,088	32,088
Suwannee 2.5 %	20,000	8,192	18,192
Suwannee 1.0 %	10,000		
		221,840	701,840
TOTAL	480,000		
LIGHT OIL (#2) BBLs			
		546	5,646
Avon Park	5,100	6,762	23,462
Bartow	16,700	6,522	25,022
Bayboro	18,500	31,817	117,158
DeBary	85,341	1,983	12,039
Higgins	10,056	26,008	116,451
Intercession City	84,443	226	1,416
Port St. Joe	1,190	124	1,422
Rio Pinar	1,298	10,338	23,838
Suwannee	13,500	6,538	36,212
Turner	29,674	3,749	23,491
Start-up ⁽²⁾	19,742		
		94,613	380,157
TOTAL	285,544		

(1) Coal based on delivery schedules; Long Range Targets: CR 1&2 150,000 Tons
CR 4&5 250,000 Tons

(2) Anclote and Crystal River



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A 231-4532
FAC TELEPHONE

SUBJECT: **Fuel Cost Projections**

TO: **Mr. M. D. Rib**
Mr. K. H. Wleland

DATE: **January 16, 1996**

Please find attached FCP 9601. This updates both the short and long term forecast prices for fuel.

If you have any questions or require additional information, please advise.

Dale Williams

Attachment:

xc: G. A. Aldazabal
L. D. Brousseau
M. L. Daley
R. D. Dolan
D. G. Edwards
J. R. Lindquist
G. E. Matzke
P. Z. McGovern
W. C. Micklon
R. D. Niekum
D. M. OShea
G. L. Peterson
J. R. Rocha
L. G. Schuster
J. L. Simpson
D. Y. Telemeco
P. E. Toomey
T. L. Waldmann
L. A. Welch
File
Forecast Book

ELECTRIC FUELS CORPORATION

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

January 4, 1996

Mr. Dale D. Williams
Principal Buyer—Fuels Supply
Fuel and Special Projects
Florida Power Corporation - H2A
3201 - 34 Street, South
St. Petersburg, Florida 33711

RE: COAL PRICE FORECAST

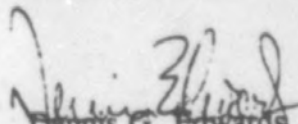
Dear Mr. Williams:

This letter is written in response to your December 1, 1995 request for updated coal-price forecasts for the Crystal River 1 & 2 and 4 & 5 quality coals, for the period 1996 through 2006. The attached schedule (Attachment A) lists our forecast of delivered coal costs for this period. Also attached are our forecasts for incremental coal prices for the same period (Attachment B). Based on information from our consultants, we are recommending that prices beyond 2006 should be trended with inflation times a .67 multiplier to reflect the forecast of these consultants that coal prices will not escalate as fast as general inflation.

We used information from the *Hill and Associates July 1995 Forecast* and *RDI's Winter 1994/1995 Coal Price Forecast* to assist us in developing this projection.

If you have any questions regarding any of the projections herein, please let me know.

Sincerely,


Dennis G. Edwards
Vice President
Coal Procurement

DGE/ro

Attachments

cc: W. D. Carter
S. M. Hopkins
D. M. Davis
R. A. Hemmer

ELECTRIC FUELS CORPORATION

Estimated Coal Prices

1996—2006

Attachment A

Crystal River 1 & 2

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	1,900	12,600	\$42.34	\$1.68
1997: January—December	1,750	12,600	\$43.09	\$1.71
1998: January—December	1,750	12,600	\$43.34	\$1.72
1999: January—December	1,700	12,600	\$44.60	\$1.77
2000: January—December	1,700	12,500	\$45.25	\$1.81
2001: January—December	1,900	12,500	\$46.00	\$1.84
2002: January—December	1,900	12,500	\$46.75	\$1.87
2003: January—December	1,900	12,500	\$48.50	\$1.94
2004: January—December	1,900	12,500	\$49.50	\$1.98
2005: January—December	1,900	12,500	\$50.25	\$2.01
2006: January—December	1,900	12,500	\$51.25	\$2.05

Crystal River 4 & 5

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	3,450	12,500	\$50.00	\$2.00
1997: January—December	3,500	12,500	\$50.50	\$2.02
1998: January—December	3,500	12,500	\$51.00	\$2.04
1999: January—December	3,500	12,500	\$51.75	\$2.07
2000: January—December	3,500	12,500	\$53.00	\$2.12
2001: January—December	3,500	12,500	\$53.75	\$2.15
2002: January—December	3,500	12,500	\$54.75	\$2.19
2003: January—December	3,500	12,500	\$55.50	\$2.22
2004: January—December	3,500	12,500	\$54.50	\$2.18
2005: January—December	3,500	12,500	\$55.50	\$2.22
2006: January—December	3,500	12,500	\$57.00	\$2.28

Crystal River 1 & 2 and 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,535	\$47.38	\$1.89
1997: January—December	12,535	\$47.88	\$1.91
1998: January—December	12,535	\$48.39	\$1.93
1999: January—December	12,535	\$49.39	\$1.97
2000: January—December	12,500	\$50.50	\$2.02
2001: January—December	12,500	\$51.00	\$2.04
2002: January—December	12,500	\$52.00	\$2.08
2003: January—December	12,500	\$53.00	\$2.12
2004: January—December	12,500	\$52.75	\$2.11
2005: January—December	12,500	\$53.50	\$2.14
2006: January—December	12,500	\$54.50	\$2.18

ELECTRIC FUELS CORPORATION
 Estimated Incremental Coal Prices
 1996—2006

Crystal River 1 & 2

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$41.45	\$1.66
1997: January—December	12,500	\$42.00	\$1.68
1998: January—December	12,500	\$43.00	\$1.70
1999: January—December	12,500	\$44.11	\$1.74
2000: January—December	12,500	\$45.00	\$1.79
2001: January—December	12,500	\$45.75	\$1.83
2002: January—December	12,500	\$46.50	\$1.86
2003: January—December	12,500	\$48.25	\$1.93
2004: January—December	12,500	\$49.00	\$1.96
2005: January—December	12,500	\$49.75	\$1.99
2006: January—December	12,500	\$50.50	\$2.02

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$43.25	\$1.73
1997: January—December	12,500	\$44.75	\$1.76
1998: January—December	12,500	\$46.00	\$1.80
1999: January—December	12,500	\$46.50	\$1.86
2000: January—December	12,500	\$47.25	\$1.89
2001: January—December	12,500	\$48.25	\$1.93
2002: January—December	12,500	\$49.50	\$1.98
2003: January—December	12,500	\$51.75	\$2.07
2004: January—December	12,500	\$53.25	\$2.13
2005: January—December	12,500	\$54.50	\$2.18
2006: January—December	12,500	\$55.75	\$2.23

FUELS SUPPLY DEPARTMENT

FCP 9601

NATURAL GAS

\$/MMBTU

Supply Cost

Jan 96 - Mar 96
Apr - Sep 96
Oct - Dec 96

2.65
1.85
1.90

Additional Transportation Cost

Firm

Demand Charge⁽¹⁾

Variable Charge

University of Florida
Suwannee

.44
.52

.25
.24

Interruptible

Variable Charge⁽²⁾

University of Florida
Bartow, Higgins, Avon Park, Crystal River
Intercession City
Suwannee

.55
.45
.50
.65

(1) 9,300 MMBtu/day for University of Florida and 10,200 MMBtu/day for Suwannee

(2) Add \$0.40/MMBtu for Premium Daily Interruptible Transportation

FUELS SUPPLY DEPARTMENT

FCP 9601

NATURAL GAS

Interruptible Transportation⁽¹⁾

Estimates of Availability

MMBTU

FLORIDA GAS TRANSMISSION

Bartow Max. Hour ⁽²⁾	2,050/hour
Higgins Max. Hour ⁽²⁾	2,100/hour
Avon Park Max. Hour	650/hour
Intercession City Max. Hour	6,000/hour

Total average pipeline availability:

Daily	30,000/day
Monthly ⁽³⁾	35,000/day
Premium Daily	25,000/day

SOUTHERN/SOUTH GEORGIA NATURAL GAS

Suwannee Max Hour	1,500/hour
-------------------	------------

Total average pipeline availability:

Jun, Jul, Aug, Dec, Jan, Feb:	6,000/day
Mar, Apr, May, Sep, Oct, Nov:	23,000/day

- (1) This may be in the form of Interruptible Tariff Transportation or Temporary Released Firm Capacity.
(2) Higgins and Bartow combined can't exceed 2,100/Hour
(3) Monthly Interruptible requires FPC to take the volume everyday of an entire month

FCP9602.DDW

January 16, 1996

FUELS SUPPLY DEPARTMENT

FCP 9601

NATURAL GAS

Long Term

\$/MMBTU

SUPPLY COST

1997	\$1.80
1998	\$1.85
1999	\$1.90
2000	\$1.95
2001	\$2.00
2002	\$2.10
2003	\$2.20
2004	\$2.30
2005	\$2.40

Escalate at 2/3 of inflation thereafter

TRANSPORTATION COST

Demand Charge

Variable Charge

Polk County:

1998

.62

.12

Escalate transportation charges at 1%/year
(See 1996 sheet for other transportation charges)

FUELS SUPPLY DEPARTMENT
FCP 9601
FUEL OIL
Delivered to Florida - West Coast
\$/MMBTU

	<u>#6 FUEL OIL</u>			<u>#2 FUEL OIL</u>
	1.0%	1.5%	2.5%	0.5%
Jan 96	3.00	2.80	2.65	4.50
Feb 96	2.75	2.55	2.50	4.20
Mar 96	2.55	2.40	2.35	4.10
Apr 96 - Sep 96	2.30	2.25	2.20	4.00
Oct 96 - Dec 96	2.55	2.40	2.35	4.10

ADDITIONAL TRANSPORTATION COST

1996

#6 Fuel Oil

Suwannee .80

#2 Fuel Oil

Anclote .12
 Avon Park .20
 Bartow/Bayboro .16
 Crystal River .21
 DeBary .24
 Higgins .09
 Intercession City .19
 Port St. Joe .24
 Rio Pinar .22
 Suwannee .21
 Turner .24

FCP9602.DDW

January 16, 1996

FUELS SUPPLY DEPARTMENT

FCP 9601

FUEL OIL

Delivered to Florida - West Coast

Long Term

\$/MMBTU

	#6 FUEL OIL			#2 FUEL OIL
	1.0%	1.5%	2.5%	0.5%
1997	2.50	2.35	2.25	4.00
1998	2.50	2.35	2.25	4.00
1999	2.50	2.35	2.25	4.10
2000	2.55	2.35	2.25	4.10
2001	2.55	2.35	2.25	4.10
2002	2.65	2.45	2.25	4.20
2003	2.75	2.55	2.35	4.40
2004	2.90	2.65	2.45	4.55
2005	3.00	2.80	2.60	4.75

Escalate at 2/3 of inflation rate thereafter

January 16, 1996

FCP9602.DDW

FUELS SUPPLY DEPARTMENT

FCP 9601

NUCLEAR FUEL

<u>CYCLE</u>	<u>DATE</u>	<u>\$/MMBTU⁽¹⁾</u>
10	6/3/94 - 2/29-96	.37
11	4/15/96 - 3/5/98	.326
12	4/15/98 - 3/1/00	.344
13	4/15/00 - 3/1/02	.353

Escalate at 2%/yr after Cycle 13 or 4% every refueling

⁽¹⁾ Does not include spent fuel disposal or enrichment plant decommissioning charges

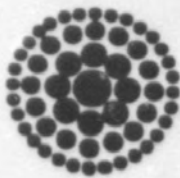
FUELS SUPPLY DEPARTMENT FCP 9601 FUEL INVENTORY TARGET LEVELS⁽¹⁾
--

	<u>INVENTORY w/o TANK BOTTOMS</u>	<u>TANK BOTTOMS</u>	<u>TOTAL INVENTORY</u>
RESIDUAL OIL (#6) BBLs.			
Anclote & Bartow South	300,000	138,346	438,346
Bartow & Bartow North	150,000	63,214	213,214
Suwannee 2.5%	20,000	12,088	32,088
Suwannee 1.0%	<u>10,000</u>	<u>8,192</u>	<u>18,192</u>
TOTAL	480,000	221,840	701,840
LIGHT OIL (#2) BBLs.			
Avon Park	5,100	546	5,646
Bartow	16,700	6,762	23,462
Bayboro	18,500	6,522	25,022
Debary	85,341	31,817	117,158
Higgins	10,056	1,983	12,039
Intercession City	84,443	26,008	110,451
Port St. Joe	1,190	226	1,416
Rio Pinar	1,298	124	1,422
Suwannee	13,500	10,338	23,838
Turner	29,674	6,538	36,212
Start-up ⁽²⁾	<u>19,742</u>	<u>3,749</u>	<u>23,491</u>
TOTAL	285,544	94,613	380,157

- (1) Coal based on delivery schedules; Long Range Targets: CR 1&2 150,000 Tons
CR 4&5 250,000 Tons
- (2) Anclote and Crystal River

January 16, 1996

FCP9602.DDW



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department

OFFICE

H2A

MAC

231-4532

TELEPHONE

JTH
AMM
File

SUBJECT: **Fuel Cost Projections**

TO: **Mr. M. D. Rib**
Mr. K. H. Wieland

DATE: **December 11, 1995**

Please find attached FCP 9502. This updates the 1995 - 1996 forecast prices for the 1996 April - September Fuel Adjustment Forecast.

If you have any questions or require additional information, please advise.

Dale Williams

Dale Williams

Attachments:

xc: G. A. Aldazabal
M. L. Daley
R. D. Dolan
D. G. Edwards
J. R. Lindquist
G. E. Matzke
P. Z. McGovern
W. C. Micklon
R. D. Niekum
D. M. OShea
G. L. Peterson
J. R. Rocha
L. G. Schuster
J. L. Simpson
D. Y. Telemeco
P. E. Toomey
T. L. Waldmann
L. A. Welch
File
Forecast Book

**ELECTRIC
FUELS
CORPORATION**

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733. (813) 824-6600

December 6, 1995

Mr. Dale D. Williams
Principal Fuel Buyer
Fuel and Special Projects—H2A
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Dear Dale:

Attached are the *January to December 1996 Coal Price Forecasts* for Crystal River Units 1 and 2 (Attachment A), Crystal River Units 4 and 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your April-September 1996 fuel adjustment filing. We have based our calculations on the latest financial estimates for 1996 provided by our Accounting Department and the assumptions listed on Appendix I.

If you require additional information, please call me or Donna Davis.

Sincerely,

Raynia A. Hemmer

Raynia A. Hemmer
Contract Administration Specialist

RAH/ro

Attachments

cc/att: Mr. W. D. Carter
Mr. D. J. Clark, Jr.
Mr. D. G. Edwards
Mrs. D. M. Davis
Mr. S. M. Hopkins

ELECTRIC FUELS CORPORATION
1996 COAL PRICE FORECAST
CRYSTAL RIVER 1 & 2

Year/Month	Tons (000)	Btu/Lb	\$/Ton	Average ¢/MBtu	Incremental ¢/MBtu
<u>1996</u>					
January	158	12,600	42.21	167.5	164.1
February	158	12,600	42.22	167.5	164.1
March	158	12,600	42.23	167.6	164.1
April	158	12,600	42.28	167.8	164.4
May	159	12,600	42.43	168.4	164.4
June	158	12,600	42.31	167.9	164.4
July	159	12,600	42.37	168.1	164.8
August	158	12,600	42.40	168.3	164.8
September	159	12,600	42.40	168.3	164.8
October	158	12,600	42.89	170.2	166.3
November	159	12,600	42.74	169.6	166.3
December	158	12,600	42.73	169.6	166.3

Attachment B

ELECTRIC FUELS CORPORATION
1996 COAL PRICE FORECAST
CRYSTAL RIVER 4 & 5

Year/Month	Tons (000)	Bcu/Lb	\$/Ton	Average €/MBcu	Incremental €/MBcu
<u>1996</u>					
January	298	12,540	49.65	198.0	170.6
February	298	12,540	49.64	197.9	170.6
March	298	12,540	49.66	198.0	170.6
April	298	12,540	49.71	198.2	170.9
May	298	12,540	49.89	198.9	171.0
June	298	12,540	49.75	198.4	171.0
July	298	12,540	49.87	198.8	171.3
August	298	12,540	49.87	198.8	171.3
September	298	12,540	49.90	199.0	171.3
October	256	12,480	51.34	205.7	172.8
November	256	12,480	51.20	205.1	172.8
December	256	12,480	51.29	205.5	172.8

ELECTRIC FUELS CORPORATION
1996 COAL PRICE FORECAST
CRYSTAL RIVER 1 & 2 AND 4 & 5

Year/Month	Tons (000)	Btu/Lb	\$/Ton	Average ¢/MBtu
<u>1996</u>				
January	456	12,561	47.07	187.4
February	456	12,561	47.07	187.4
March	456	12,561	47.09	187.4
April	456	12,561	47.14	187.6
May	457	12,561	47.29	188.2
June	456	12,561	47.17	187.8
July	457	12,561	47.26	188.1
August	456	12,561	47.28	188.2
September	457	12,561	47.29	188.2
October	414	12,526	48.12	192.1
November	415	12,526	47.96	191.4
December	414	12,526	48.02	191.7



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS APRIL 1—SEPTEMBER 30, 1996 PAGE 1 OF 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE. AN INFLATION ASSUMPTION OF 2.5% FOR 1996 (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- TWO NEW CRYSTAL RIVER 1 & 2 RAIL-DELIVERED COAL CONTRACTS EFFECTIVE JANUARY 1, 1996, TOTALLING 800,000 TONS HAVE REPLACED CONTRACTS EXPIRING IN 1995. TWO NEW ONE-YEAR CRYSTAL RIVER 4 & 5 RAIL-DELIVERED COAL CONTRACTS TOTALLING 500,000 TONS EFFECTIVE OCTOBER 1, 1995, REPLACED THE TONNAGE REDUCTION ON AN EXISTING CONTRACT RESULTING FROM A MARKET REOPENER IN 1995. NO MARKET REOPENERS ARE APPLICABLE IN 1996.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S AND HILL & ASSOCIATES' (EFC'S COAL INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL MARKET INFORMATION.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT AN INFLATION ASSUMPTION OF 2.5% (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT TWO SETS OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF DECEMBER 31, 1995, AND DECEMBER 1, 1996, AT A COST PER SET OF APPROXIMATELY \$5.7 AND \$5.8 MILLION, RESPECTIVELY.
- 1996 WATER FREIGHT IS ESTIMATED AT THE CURRENT MARKET RATE ESCALATED AT THE FORECASTED CHANGE OF THE INDIVIDUAL INDICES, IN ACCORDANCE WITH THE WATERBORNE COMPONENT PROVISIONS.



APPENDIX I
EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS
APRIL 1—SEPTEMBER 30, 1996
PAGE 2 OF 2

GENERAL ADMINISTRATION

- COSTS ARE BASED ON THE 1996 ANNUAL PLAN.
- 37 PERCENT EFFECTIVE TAX RATE ASSUMED FOR INCOME TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON FPC'S TOTAL REQUIREMENT OF 5,350,000 TONS FOR 1996.

EFC/RAH
12/06/95

FUELS SUPPLY DEPARTMENT

FCP 9502

NUCLEAR FUEL

CYCLE

DATES

\$/MMBTU⁽¹⁾

10

6/3/94 - 2/29/96

.37

11

4/15/96 - 3/5/98

.326

⁽¹⁾ Does not include spent fuel disposal or enrichment plant decommissioning charges

FUELS SUPPLY DEPARTMENT
FCP 9502
FUEL OIL
Delivered to Florida - West Coast

\$/MMBtu

	<u>#6 Fuel Oil</u>			<u>#2 Fuel Oil</u>
	1.0%	1.5%	2.5%	0.5%
Dec 95 - Mar 96	2.50	2.45	2.35	4.10
Apr - Jun 96	2.30	2.25	2.20	3.60
Jul - Sep 96	2.15	2.10	2.05	3.60
Oct - Dec 96	2.40	2.35	2.30	3.80

Additional Transportation Cost

\$/MMBtu

1996

#6 Fuel Oil

Suwannee .70

#2 Fuel Oil

Anclote .12
 Avon Park .20
 Bartow/Bayboro .16
 Crystal River .21
 DeBary .24
 Higgins .09
 Intercession City .19
 Port St. Joe .24
 Rio Pinar .22
 Suwannee .21
 Turner .24

FUELS SUPPLY DEPARTMENT
FCP 9502
NATURAL GAS

Supply Cost
\$/MMBtu

Dec 95 - Mar 96	2.00
Apr - Sep 96	1.75
Oct - Dec 96	1.80

Additional Transportation Cost
\$/MMBtu

<u>Firm</u>	<u>Demand Charge¹</u>	<u>Variable Charge</u>
University of Florida	.44	.25
Suwannee	.52	.24
		<u>Variable Charge</u>
<u>Interruptible</u>		.55
University of Florida		.45
Bartow, Higgins, Avon Park		.50
Intercession City		.65
Suwannee		

¹ 9,300 MMBtu/day for University of Florida and 10,200 MMBtu/day for Suwannee

FUELS SUPPLY DEPARTMENT

FCP 9502

Natural Gas - Interruptible Transportation¹

Estimates of Availability

MMBTU

FLORIDA GAS TRANSMISSION

	OCT - MAR	APR - SEP
Bartow ² Max Hour	2,000	2,100
Higgins ² Max Hour	2,100	2,100
Avon Park Max Hour	600	700
Intercession City Max Hour	8,500	8,500

Total available supply: 50,000/day

SOUTHERN/SOUTH GEORGIA NATURAL GAS

Suwannee Max Hour	1,500	1,500
----------------------	-------	-------

Total available supply:

Jun, Jul, Aug, Dec, Jan, Feb: 6,000 day

Mar, Apr, May, Sep, Oct, Nov: 23,000 day

¹ This may also be in the form of temporary released firm capacity

² Higgins and Bartow combined can't exceed 2,100/hr

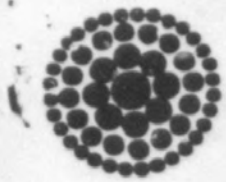
FUELS SUPPLY DEPARTMENT
FCP 9502
FUEL INVENTORY TARGET LEVELS¹

	<u>INVENTORY w/o TANK BOTTOMS</u>	<u>TANK BOTTOMS</u>	<u>TOTAL INVENTORY</u>
RESIDUAL OIL (#6) BBLs.			
Anclote & Bartow South	300,000	138,346	438,346
Bartow & Bartow North	150,000	63,214	213,214
Suwannee 2.5%	20,000	12,088	32,088
Suwannee 1.0%	<u>10,000</u>	<u>8,192</u>	<u>18,192</u>
TOTAL	480,000	221,840	701,840
LIGHT OIL (#2) BBLs.			
Avon Park	5,100	546	5,646
Bartow	16,700	6,762	23,462
Bayboro	18,500	6,522	25,022
Debary	85,341	31,817	117,158
Higgins	10,056	1,983	12,039
Intercession City	84,443	26,008	110,451
Port St. Joe	1,190	226	1,416
Rio Pinar	1,298	124	1,422
Suwannee	13,500	10,338	23,838
Turner	29,674	6,538	36,212
Start-up ²	<u>19,742</u>	<u>3,749</u>	<u>23,491</u>
TOTAL	285,544	94,613	380,157

¹ Coal based on delivery schedules; Long Range Targets:

CR 1&2 150,000 Tons
 CR 4&5 250,000 Tons

² Anclote and Crystal River



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A 231-4532
MAC TELEPHONE

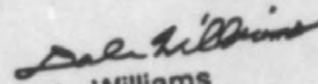
SUBJECT: **Fuel Cost Projections**

DATE: **October 31, 1995**

TO: **Mr. M. D. Rib
Mr. K. H. Wieland**

Please find attached a Preliminary Update to FCP 9501. This updates the 1995 - 1997 forecast prices for natural gas and fuel oil. A more comprehensive short range update will be prepared in mid-December for the 1996 April - September Fuel Adjustment Forecast.

If you have any questions or require additional information, please advise.


Dale Williams

Attachments:

xc: K. L. Anthony
L. D. Brousseau
M. L. Daley
R. D. Dolan
D. G. Edwards
J. R. Lindquist
G. E. Matzke
P. Z. McGovern
W. C. Micklon
R. D. Niekum
D. M. OShea
J. R. Rocha
L. G. Schuster
R. L. Simpson
D. Y. Telemeco
P. E. Toomey
L. A. Welch
File
Forecast Book

FUELS SUPPLY DEPARTMENT FCP 9501 - 10/31/95 Preliminary Update/DDW NATURAL GAS \$/MMBTU
--

FIRM TRANSPORTATION

<u>U of F</u>	<u>Supply Cost¹</u>	<u>Var Transp²</u>	<u>Fixed³</u>	<u>Total⁴</u>
5/95 - 10/95	1.65	.21	.43	2.29
11/95 - 10/96	1.75	.22	.43	2.40
11/96 - 12/96	1.80	.23	.43	2.46
1997	1.90	.23	.43	2.56

Suwannee

5/95 - 10/95	1.65	.19	.53	2.37
11/95 - 10/96	1.75	.20	.53	2.48
11/96 - 12/96	1.80	.20	.53	2.53
1997	1.90	.20	.53	2.63

INTERRUPTIBLE TRANSPORTATION

Bartow, Higgins,
Avon Park

5/95 - 10/95	1.65	.35	--	2.00
11/95 - 11/96	1.75	.41	--	2.16
11/96 - 12/96	1.80	.42	--	2.22
1997	1.90	.42	--	2.32

Intercession City: Add .05 to transportation rates for KUA charges

¹ 1000 BTU/cf

² Includes compressor fuel cost, variable surcharges and variable transportation charges (including GRU charge for U of F).

³ Based on 9,300 MMBtu/day for U of F and 10,000 MMBtu/day for Suwannee Plant. Both plants are limited to 6% of daily contract amount per hour.

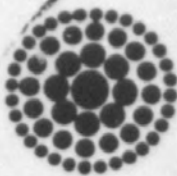
⁴ At 100% load factor for Firm Transportation.

FUELS SUPPLY DEPARTMENT
FCP 9501 10/31/95 Preliminary Update/DDW
FUEL OIL
Delivered to Florida - West Coast
\$/MMBTU

	<u>#6 - 1.0% S</u>	Low API <u>#6 - 1.5% S</u>	Low API <u>#6 - 2.5% S</u>	<u>#2 - 0.5% S</u>
5/95 - 12/95	2.50	2.40	2.30	4.00
1996	2.50	2.40	2.30	4.00
1997	2.70	2.60	2.50	4.20

10/31/95
D. D. Williams

FCP9501.2



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

SUBJECT: Fuel Cost Projections

TO: Mr. M. D. Rib
Mr. K. H. Wieland

DATE: May 30, 1995

Please find attached FCP 9501. This updates the Short and Long Term Fuel Forecast as well as the High Case and Low Case Scenarios.

If you have any questions or require additional information, please advise.

Dale Williams
Dale Williams

Attachments:

xc: K. L. Anthony
L. D. Brousseau
R. D. Dolan
D. G. Edwards
J. R. Lindquist
G. E. Matzke
P. Z. McGovern
W. C. Micklon
R. D. Niekum
D. M. OShea
J. R. Rocha
J. L. Simpson
P. E. Toomey/L. G. Schuster
File
Forecast Book

FUELS SUPPLY DEPARTMENT

FCP 9501

NUCLEAR FUEL COST⁽¹⁾

<u>CYCLE</u>	<u>DATES</u>	<u>\$/MMBTU</u>
10	6/3/94 - 2/29/96	.371
11	4/15/96 - 3/5/98	.329
12	4/19/98 - 3/2/00	.349
13	4/17/00 - 2/28/02	.376
14	4/14/02 - 3/4/04	.389
15	4/11/04 - 3/2/06	.408

Escalate at 70% of inflation after 3/2/06

⁽¹⁾ Does not include spent fuel disposal or enrichment plant decommissioning cost

FUELS SUPPLY DEPARTMENT**FCP 9501****FUEL OIL****Delivered to Florida - West Coast****\$/MMBTU**

	<u>#6 - 1.0% S</u>	<u>#6 - 1.5% S</u>	<u>#6 - 2.5% S</u>	<u>#2 - 0.5% S</u>
5/95 - 12/95	2.80	2.77	2.70	4.30
1996	2.80	2.77	2.70	4.30
1997	2.75	2.72	2.65	4.30
1998	2.80	2.77	2.70	4.40
1999	2.90	2.88	2.85	4.70
2000	3.00	2.98	2.95	4.90
2001	3.15	3.13	3.10	5.05
2002	3.25	3.23	3.20	5.10
2003	3.35	3.33	3.30	5.25
2004	3.45	3.43	3.40	5.40
2005	3.50	3.48	3.45	5.60

Escalate at 85% of inflation after 2005

5/16/95

D. D. Williams

FCP9501.1

FUELS SUPPLY DEPARTMENT
FCP 9501
OIL TRANSPORTATION COST
\$/MMBTU

1995

Residual Fuel Oil

Suwannee	.66 ¹
----------	------------------

Light Fuel Oil

Anclote	.11
Avon Park	.19
Bartow/Bayboro	.16
Crystal River	.19
Debary	.23
Higgins	.09
Intercession City ²	.14
Port St. Joe	.52
Rio Pinar	.22
Suwannee	.23
Turner	.23

¹ Based on minimum volume of 100,000 BBLS/yr.

² Add \$24,000/month for dedicated storage in Tampa

FUELS SUPPLY DEPARTMENT
FCP 9501
NATURAL GAS
\$/MMBTU

D R A F T

FIRM TRANSPORTATION

<u>U of F</u>	<u>Supply Cost¹</u>	<u>Var Transp²</u>	<u>Fixed³</u>	<u>Total⁴</u>
5/95 - 10/95	1.65	.21	.43	2.29
11/95 - 10/96	1.80	.22	.43	2.45
11/96 - 12/96	2.00	.23	.43	2.66

Suwannee

5/95 - 10/95	1.65	.19	.53	2.37
11/95 - 10/96	1.80	.20	.53	2.53
11/96 - 12/96	2.00	.20	.53	2.73

INTERRUPTIBLE TRANSPORTATION

**Bartow, Higgins,
Avon Park**

5/95 - 10/95	1.65	.35	--	2.00
11/95 - 11/96	1.80	.41	--	2.21
11/96 - 12/96	2.00	.42	--	2.42

Intercession City: Add .05 to transportation rates for KUA charges

¹ 1000 BTU/cf

² Includes compressor fuel cost, variable surcharges and variable transportation charges (including GRU charge for U of F).

³ Based on 9,300 MMBtu/day for U of F and 10,000 MMBtu/day for Suwannee Plant. U of F will have a take-or-pay settlement charge of \$97,790 per month for June - November 1995. Both plants are limited to 6% of daily contract amount per hour.

⁴ At 100% load factor for Firm Transportation.

5/1/95
D. D. Williams

FCP9501.1

FUELS SUPPLY DEPARTMENT**FCP 9501****NATURAL GAS \$/MMBTU****U of F Long Term Forecast**

	<u>SUPPLY COST</u>	<u>VAR TRANSP</u>	<u>FIXED</u>	<u>TOTAL</u>
1997	1.95	.23	.43	2.61
1998	2.05	.23	.43	2.71
1999	2.15	.23	.44	2.82
2000	2.30	.24	.44	2.98
2001	2.45	.24	.45	3.14
2002	2.60	.25	.45	3.30
2003	2.75	.25	.46	3.46
2004	2.90	.26	.46	3.62
2005	3.00	.26	.47	3.73

Escalate at 85% of inflation after 2005

5/1/95

D. D. Williams

FCP9501.1

FUELS SUPPLY DEPARTMENT
FCP 9501
NATURAL GAS \$/MMBTU
Suwannee Plant - Long Term Forecast

	<u>SUPPLY COST</u>	<u>VAR TRANSP</u>	<u>FIXED</u>	<u>TOTAL</u>
1997	1.95	.20	.53	2.68
1998	2.05	.20	.53	2.78
1999	2.15	.20	.54	2.89
2000	2.30	.21	.54	3.05
2001	2.45	.21	.55	3.21
2002	2.60	.22	.55	3.37
2003	2.75	.22	.56	3.53
2004	2.90	.23	.56	3.69
2005	3.00	.23	.57	3.80

Escalate at 85% of inflation after 2005

5/1/95

D. D. Williams

FCP9501.1

FUELS SUPPLY DEPARTMENT**FCP 9501****NATURAL GAS****POLK COUNTY****\$/MMBTU**

	<u>SUPPLY COST</u>	<u>VAR TRANSP</u>	<u>FIXED</u>	<u>TOTAL</u>
1998	2.05	.11	.76	2.92
1999	2.15	.11	.76	3.02
2000	2.30	.12	.77	3.19
2001	2.45	.12	.77	3.34
2002	2.60	.13	.78	3.51
2003	2.75	.13	.78	3.66
2004	2.90	.14	.79	3.83
2005	3.00	.14	.79	3.93

Escalate at 85% of inflation after 2005

FUELS SUPPLY DEPARTMENT

FCP 9501

Natural Gas - Interruptible Transportation¹ Florida Gas Volume Estimates of Availability MMBTU

	OCT - MAR	APR - SEP
Bartow ² Max Hour	2000	2100
Higgins ² Max Hour	2100	2100
Avon Park Max Hour	600	700
Intercession City Max Hour	8500	8500

Total available supply: 50,000/day

¹ This may also be in the form of temporary released firm capacity

² Higgins and Bartow combined can't exceed 2100/hr

FUELS SUPPLY DEPARTMENT**FCP 9501****NATURAL GAS - \$/MMBTU****Interruptible Gas - Long Term**

	<u>SUPPLY COST</u>	<u>TRANSPORTATION</u>	<u>TOTAL</u>
1997	1.95	.42	2.37
1998	2.05	.43	2.48
1999	2.15	.44	2.59
2000	2.30	.45	2.75
2001	2.45	.46	2.91
2002	2.60	.47	3.07
2003	2.75	.48	3.23
2004	2.90	.49	3.39
2005	3.00	.50	3.50

Escalate at 85% of inflation after 2005

FUELS SUPPLY DEPARTMENT

FCP 9501

PETROLEUM COKE

\$/MMBTU

CRYSTAL RIVER

INLAND FREIGHT

POLK COUNTY

1996	1.08	.20	1.28
1997	1.11	.20	1.31
1998	1.15	.21	1.36
1999	1.18	.22	1.40
2000	1.21	.23	1.44
2001	1.25	.24	1.49
2002	1.29	.25	1.54
2003	1.33	.26	1.59
2004	1.37	.27	1.64
2005	1.41	.28	1.69

- Market price from various suppliers plus EFC freight to Crystal River. Inland Freight based on estimated truck freight.
- Escalate at inflation after 2005.
- 14,000 BTU/lb.

FUELS SUPPLY DEPARTMENT**FCP 9501****ORIMULSION - BASE CASE****\$/MMBTU¹**

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
1999	1.65	.41	2.06
2000	1.69	.42	2.11
2001	1.73	.43	2.16
2002	1.74	.43	2.20
2003	1.81	.44	2.25
2004	1.84	.45	2.29
2005	1.87	.45	2.32

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 45% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

FUELS SUPPLY DEPARTMENT
FCP 9501
FUEL INVENTORY TARGET LEVELS¹

	<u>INVENTORY w/o TANK BOTTOMS</u>	<u>TANK BOTTOMS</u>	<u>TOTAL INVENTORY</u>
RESIDUAL OIL (#6) BBLs.			
Anclote & Bartow South	240,000		
Bartow & Bartow North	200,000	138,346	378,346
Suwannee 2.5%	20,000	63,214	263,214
Suwannee 1.0%	<u>10,000</u>	12,088	32,088
		<u>8,192</u>	<u>18,192</u>
TOTAL	470,000	221,840	691,840
LIGHT OIL (#2) BBLs.			
Avon Park	5,100		
Bartow	16,700	546	5,646
Bayboro	18,500	6,762	23,462
Debary	85,341	6,522	25,022
Higgins	10,056	31,817	117,158
Intercession City	84,443	1,983	12,039
Port St. Joe	1,190	26,008	110,451
Rio Pinar	1,298	226	1,416
Suwannee	13,500	124	1,422
Turner	29,674	10,338	23,838
Start-up ²	<u>19,742</u>	6,538	36,212
		<u>3,749</u>	<u>23,491</u>
TOTAL	285,544	94,613	380,157

¹ Coal based on delivery schedules

² Anclote and Crystal River



ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

MAY 15 1995

May 15, 1995

Mr. Dale D. Williams
Principal Fuel Buyer
FLORIDA POWER CORPORATION
P. O. Box 14042
St. Petersburg, Florida 33733

Dear Dale:

Attached are the June 1995 to March 1996 coal-price forecasts for Crystal River Units 1 & 2 (Attachment A), Crystal River Units 4 & 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your October 1995 - March 1996 fuel-adjustment filing. We have based our calculations on the latest financial estimates for 1995 and 1996 provided by our Accounting Department, and the assumptions listed on Appendix I.

If you require additional information, please call me or Donna Davis.

Sincerely,

ELECTRIC FUELS CORPORATION

A handwritten signature in cursive script that reads 'Raynia A. Hemmer'.

Raynia A. Hemmer
Contract Administration Specialist

RAH:jss
Attachments

cc: W. D. Carter
D. J. Clark, Jr.
D. M. Davis
D. G. Edwards
S. M. Hopkins

ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2

	Tons (000s)	Btu/lb.	\$/Ton	Average ¢/MMBtu	Incremental ¢/MMBtu
<u>1995</u>					
June	123	12,494	44.75	179.07	162.24
July	123	12,493	44.75	179.07	162.24
August	123	12,493	44.75	179.07	162.24
September	123	12,493	44.75	179.07	162.68
October	123	12,493	44.75	179.07	162.68
November	123	12,494	44.75	179.07	162.68
December	123	12,493	44.75	179.07	162.68
<u>1996</u>					
January	146	12,557	43.52	173.30	164.65
February	146	12,557	43.45	173.05	164.13
March	146	12,557	43.47	173.11	164.13

**ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST
CRYSTAL RIVER 4 & 5**

	Tons (000s)	Btu/lb.	\$/Ton	Average ¢/MMBtu	Incremental ¢/MMBtu
<u>1995</u>					
June	295	12,560	49.37	196.14	170.00
July	295	12,585	49.37	196.14	170.00
August	295	12,585	49.37	196.16	170.00
September	295	12,583	49.36	196.11	170.00
October	295	12,585	49.49	196.62	170.00
November	295	12,585	49.63	197.18	170.00
December	295	12,585	49.47	196.54	170.00
<u>1996</u>					
January	292	12,542	50.25	200.37	173.00
February	291	12,542	50.27	200.42	173.00
March	292	12,542	50.28	200.48	173.00

ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2 and 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average ¢/MMBtu
<u>1995</u>				
June	418	12,541	48.01	191.41
July	418	12,558	48.01	191.15
August	418	12,558	48.01	191.15
September	418	12,557	48.00	191.13
October	418	12,558	48.10	191.51
November	418	12,558	48.19	191.87
December	418	12,558	48.08	191.43
<u>1996</u>				
January	438	12,547	48.01	191.32
February	437	12,547	47.99	191.24
March	438	12,547	48.00	191.28



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1, 1995 - MARCH 31, 1996 Page 1 of 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE AS OF MARCH 1995. THE FLORIDA PROGRESS CORPORATE ANNUAL PROFIT PLAN (THE PLAN) INFLATION ASSUMPTION OF 3.5% FOR 1995 AND 1996 (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- THREE CR 1 & 2 CONTRACTS, TOTALING 800,000 TONS, EXPIRE BY THE END OF 1995; AND FORECASTED REPLACEMENT IS WITH TWO NEW 300,000-TON CONTRACTS AND BY EXTENDING ONE OF THE EXISTING CONTRACTS. TWO CR 4 & 5 CONTRACTS REFLECT MARKET REOPENER PRICES IN JANUARY 1995, AND ONE IN JULY 1995. NO MARKET REOPENERS ARE APPLICABLE IN 1996.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET-PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S AND HILL AND ASSOCIATES' (EFC'S COAL-INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL-MARKET INTELLIGENCE.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT THE PLAN INFLATION ASSUMPTION OF 3.5% FOR 1995 AND 1996 (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT TWO SETS OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF DECEMBER 1, 1995, AND FEBRUARY 1, 1996, AT A COST PER SET OF APPROXIMATELY \$5.7 AND \$5.8 MILLION, RESPECTIVELY.
- 1995 AND 1996 WATER FREIGHT IS ESTIMATED AT THE CURRENT MARKET RATE ESCALATED AT THE FORECASTED ESCALATION OF THE INDIVIDUAL INDICES, IN ACCORDANCE WITH ESCALATION PROVISIONS OF THE WATERBORNE COMPONENT.



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1, 1995 - MARCH 31, 1996 Page 2 of 2

GENERAL ADMINISTRATION

- COSTS ARE BASED ON THE 1995 ANNUAL PLAN.
- 37 PERCENT EFFECTIVE TAX RATE ASSUMED FOR INCOME-TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON EFC'S 1995 ANNUAL PLAN, WHICH REFLECTED A TOTAL REQUIREMENT OF 5,100,000 TONS FOR 1995, AND 5,250,000 TONS FOR 1996.
- 1995 CONTRACT TONNAGE INCLUDES 147,000 TONS DEFERRED (PEN COAL) FROM 1994 TO 1995 AT EFC'S REQUEST.



ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733. (813) 824-6600

MAY 16 1995

May 16, 1995

Mr. Dale D. Williams
Principal Buyer—Fuels Supply
Fuel and Special Projects
Florida Power Corporation - H2A
3201 - 34 Street, South
St. Petersburg, Florida 33711

Re: Coal Price Forecast

Dear Mr. Williams:

This letter is written in response to your recent request for updated coal-price forecasts for the Crystal River 1 & 2 and 4 & 5 quality coals, for the period 1996 through 2006. The attached schedule (Attachment A) lists our forecast of delivered coal costs for this period. "High" and "Low" cases for this same period are also attached (Attachments H-A and L-A). Also attached are our forecasts for incremental coal prices for the same period (Attachment B) and the incremental "High" and "Low" cases (Attachments H-B & L-B). Based on information from our consultants, we are recommending that prices beyond 2006 should be trended with inflation times a .67 multiplier to reflect the forecast of these consultants that coal prices will not escalate as fast as general inflation.

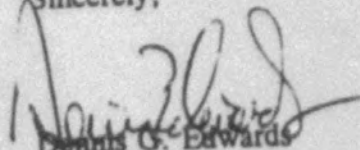
Regarding your request for price forecasts for coals supplied to the Polk County site, we have developed Attachment C. This Attachment presents 4 lb SO₂ Illinois Basin coal. Attachments H-C and L-C are the "High" and "Low" cases for Polk County "High Sulfur" coals. In addition, we have developed Attachment D to respond to your request for price estimates of "High Sulfur" coal delivered to Crystal River. Attachments H-D and L-D are the "High" and "Low" cases for "High Sulfur" coals delivered to Crystal River.

Please note that the prices for "High-Sulfur" coal are projected to increase at a much slower rate than our lower sulfur coals forecast because of forecasted reduced demand for this quality coal in the future. We used information from the *Hill and Associates May 1994 Forecast* to assist us in developing this projection as their 1995 Forecast has not yet been published.

Mr. Dale D. Williams
May 16, 1995
Page 2

If you have any questions regarding any of the projections herein, please let me know.

Sincerely,



Dennis G. Edwards
Vice President
Coal Procurement

DGE/ro

Attachments

cc: W. D. Carter
S. M. Hopkins
D. M. Davis
R. A. Hemmer

INDEX OF ATTACHMENTS

<i>Attachment A</i>	Base Case costs for Crystal River 1 & 2, Crystal River 4 & 5 and all units combined.
<i>Attachment H-A</i>	Same as A except costs represent "high side" of likely cost range.
<i>Attachment L-A</i>	Same as A except costs represent "low side" of likely cost range.
<i>Attachment B</i>	Base Case "Incremental Costs" for Crystal River 1 & 2 and Crystal River 4 & 5; i.e., spot coal delivered by leased railcars.
<i>Attachment H-B</i>	Same as B except costs represent "high side" of likely cost range.
<i>Attachment L-B</i>	Same as B except costs represent "low side" of likely cost range.
<i>Attachment C</i>	Base Case costs for +4 lb SO ₂ coal from Illinois Basin delivered to the Polk County site.
<i>Attachment H-C</i>	Same as C except costs represent "high side" of likely cost range.
<i>Attachment L-C</i>	Same as C except costs represent "low side" of likely cost range.
<i>Attachment D</i>	Base Case costs for +4 lb SO ₂ coal from Illinois Basin delivered to the Crystal River complex.
<i>Attachment H-D</i>	Same as D except costs represent the "high side" of likely cost range.
<i>Attachment L-D</i>	Same as D except costs represent the "low side" of likely cost range.

ELECTRIC FUELS CORPORATIONEstimated Coal Prices
1996—2006*Crystal River 1 & 2*

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	1,750	12,500	\$43.50	\$1.74
1997: January—December	1,750	12,500	\$44.25	\$1.77
1998: January—December	1,750	12,500	\$44.75	\$1.79
1999: January—December	1,700	12,500	\$45.75	\$1.83
2000: January—December	1,700	12,500	\$47.19	\$1.89
2001: January—December	1,700	12,500	\$48.26	\$1.93
2002: January—December	1,700	12,500	\$49.25	\$1.97
2003: January—December	1,700	12,500	\$50.25	\$2.01
2004: January—December	1,700	12,500	\$51.25	\$2.05
2005: January—December	1,700	12,500	\$52.25	\$2.09
2006: January—December	1,700	12,500	\$53.25	\$2.13

Crystal River 4 & 5

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	3,500	12,616	\$50.71	\$2.01
1997: January—December	3,500	12,616	\$51.73	\$2.05
1998: January—December	3,500	12,616	\$52.48	\$2.08
1999: January—December	3,500	12,623	\$53.57	\$2.12
2000: January—December	3,500	12,623	\$54.70	\$2.17
2001: January—December	3,500	12,623	\$56.31	\$2.23
2002: January—December	3,500	12,623	\$57.57	\$2.28
2003: January—December	3,500	12,623	\$58.83	\$2.33
2004: January—December	3,500	12,623	\$59.84	\$2.37
2005: January—December	3,500	12,623	\$60.84	\$2.41
2006: January—December	3,500	12,623	\$61.85	\$2.45

Crystal River 1 & 2 and 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,578	\$48.31	\$1.92
1997: January—December	12,578	\$49.31	\$1.96
1998: January—December	12,578	\$49.82	\$1.98
1999: January—December	12,583	\$51.02	\$2.03
2000: January—December	12,583	\$52.24	\$2.08
2001: January—December	12,583	\$53.60	\$2.13
2002: January—December	12,583	\$54.91	\$2.18
2003: January—December	12,583	\$56.13	\$2.23
2004: January—December	12,583	\$57.09	\$2.27
2005: January—December	12,583	\$58.10	\$2.31
2006: January—December	12,583	\$59.11	\$2.35

ELECTRIC FUELS CORPORATION

Estimated Coal Prices

1996—2006

Attachment H-A

High Case

Crystal River 1 & 2

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	1,750	12,500	\$45.00	\$1.80
1997: January—December	1,750	12,500	\$46.00	\$1.84
1998: January—December	1,750	12,500	\$47.00	\$1.88
1999: January—December	1,700	12,500	\$48.50	\$1.94
2000: January—December	1,700	12,500	\$49.75	\$1.99
2001: January—December	1,700	12,500	\$51.25	\$2.05
2002: January—December	1,700	12,500	\$52.50	\$2.10
2003: January—December	1,700	12,500	\$53.75	\$2.15
2004: January—December	1,700	12,500	\$55.00	\$2.20
2005: January—December	1,700	12,500	\$56.25	\$2.25
2006: January—December	1,700	12,500	\$57.50	\$2.30

Crystal River 4 & 5

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	3,250	12,664	\$52.43	\$2.07
1997: January—December	3,250	12,664	\$53.95	\$2.13
1998: January—December	3,250	12,664	\$55.22	\$2.18
1999: January—December	3,250	12,669	\$56.51	\$2.23
2000: January—December	3,250	12,669	\$57.78	\$2.28
2001: January—December	3,250	12,669	\$59.55	\$2.35
2002: January—December	3,250	12,669	\$61.07	\$2.41
2003: January—December	3,250	12,669	\$62.84	\$2.48
2004: January—December	3,250	12,669	\$64.36	\$2.54
2005: January—December	3,250	12,669	\$65.88	\$2.60
2006: January—December	3,250	12,669	\$67.40	\$2.66

Crystal River 1 & 2 and 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,606	\$49.92	\$1.98
1997: January—December	12,606	\$51.18	\$2.03
1998: January—December	12,606	\$52.44	\$2.08
1999: January—December	12,611	\$53.72	\$2.13
2000: January—December	12,611	\$54.98	\$2.18
2001: January—December	12,611	\$56.75	\$2.25
2002: January—December	12,611	\$58.00	\$2.30
2003: January—December	12,611	\$59.77	\$2.37
2004: January—December	12,611	\$61.03	\$2.42
2005: January—December	12,611	\$62.55	\$2.48
2006: January—December	12,611	\$64.06	\$2.54

ELECTRIC FUELS CORPORATION
Estimated Coal Prices
1996—2006

Attachment L-A

Low Case
Crystal River 1 & 2

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1996: January—December	1,875	12,500	\$42.50	\$1.70
1997: January—December	1,875	12,500	\$43.00	\$1.72
1998: January—December	1,875	12,500	\$43.25	\$1.73
1999: January—December	1,825	12,500	\$44.25	\$1.77
2000: January—December	1,825	12,500	\$45.50	\$1.82
2001: January—December	1,825	12,500	\$46.50	\$1.86
2002: January—December	1,825	12,500	\$47.50	\$1.90
2003: January—December	1,825	12,500	\$48.50	\$1.94
2004: January—December	1,825	12,500	\$49.50	\$1.98
2005: January—December	1,825	12,500	\$50.50	\$2.02
2006: January—December	1,825	12,500	\$51.50	\$2.06

Crystal River 4 & 5

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1996: January—December	3,625	12,612	\$49.68	\$1.97
1997: January—December	3,625	12,612	\$50.44	\$2.00
1998: January—December	3,625	12,612	\$51.20	\$2.03
1999: January—December	3,625	12,619	\$51.99	\$2.06
2000: January—December	3,625	12,619	\$52.75	\$2.09
2001: January—December	3,625	12,619	\$54.01	\$2.14
2002: January—December	3,625	12,619	\$55.02	\$2.18
2003: January—December	3,625	12,619	\$56.28	\$2.23
2004: January—December	3,625	12,619	\$57.29	\$2.27
2005: January—December	3,625	12,619	\$58.30	\$2.31
2006: January—December	3,625	12,619	\$59.31	\$2.35

Crystal River 1 & 2 and 4 & 5

Year	Btu/lb	\$/Ton	Average \$/MBtu
1996: January—December	12,576	\$47.28	\$1.88
1997: January—December	12,576	\$47.79	\$1.90
1998: January—December	12,576	\$48.54	\$1.93
1999: January—December	12,579	\$49.06	\$1.95
2000: January—December	12,579	\$49.82	\$1.98
2001: January—December	12,579	\$51.07	\$2.03
2002: January—December	12,579	\$52.08	\$2.07
2003: January—December	12,579	\$53.09	\$2.11
2004: January—December	12,579	\$54.09	\$2.15
2005: January—December	12,579	\$55.10	\$2.19
2006: January—December	12,579	\$56.11	\$2.23

ELECTRIC FUELS CORPORATION
 Estimated Incremental Coal Prices
 1996—2006

Crystal River 1 & 2

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$41.45	\$1.66
1997: January—December	12,500	\$42.00	\$1.68
1998: January—December	12,500	\$43.00	\$1.72
1999: January—December	12,500	\$44.11	\$1.76
2000: January—December	12,500	\$45.00	\$1.80
2001: January—December	12,500	\$46.25	\$1.85
2002: January—December	12,500	\$47.50	\$1.90
2003: January—December	12,500	\$48.50	\$1.94
2004: January—December	12,500	\$49.75	\$1.99
2005: January—December	12,500	\$50.75	\$2.03
2006: January—December	12,500	\$52.00	\$2.08

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$43.25	\$1.73
1997: January—December	12,500	\$44.75	\$1.79
1998: January—December	12,500	\$46.00	\$1.84
1999: January—December	12,500	\$47.75	\$1.91
2000: January—December	12,500	\$49.25	\$1.97
2001: January—December	12,500	\$50.75	\$2.03
2002: January—December	12,500	\$52.25	\$2.09
2003: January—December	12,500	\$53.75	\$2.15
2004: January—December	12,500	\$55.25	\$2.21
2005: January—December	12,500	\$56.75	\$2.27
2006: January—December	12,500	\$58.25	\$2.33

ELECTRIC FUELS CORPORATION

Estimated Incremental Coal Prices

1996—2006

*High Case**Crystal River 1 & 2*

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$42.75	\$1.71
1997: January—December	12,500	\$43.50	\$1.74
1998: January—December	12,500	\$45.00	\$1.80
1999: January—December	12,500	\$46.00	\$1.84
2000: January—December	12,500	\$47.25	\$1.89
2001: January—December	12,500	\$48.50	\$1.94
2002: January—December	12,500	\$50.00	\$2.00
2003: January—December	12,500	\$51.00	\$2.04
2004: January—December	12,500	\$52.50	\$2.10
2005: January—December	12,500	\$53.50	\$2.14
2006: January—December	12,500	\$54.75	\$2.19

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$44.50	\$1.78
1997: January—December	12,500	\$46.50	\$1.86
1998: January—December	12,500	\$47.75	\$1.91
1999: January—December	12,500	\$49.75	\$1.99
2000: January—December	12,500	\$51.25	\$2.05
2001: January—December	12,500	\$52.75	\$2.11
2002: January—December	12,500	\$54.50	\$2.18
2003: January—December	12,500	\$56.00	\$2.24
2004: January—December	12,500	\$57.75	\$2.31
2005: January—December	12,500	\$59.25	\$2.37
2006: January—December	12,500	\$60.75	\$2.43

ELECTRIC FUELS CORPORATION
 Estimated Incremental Coal Prices
 1996—2006

Low Case

Crystal River 1 & 2

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$40.50	\$1.62
1997: January—December	12,500	\$41.00	\$1.64
1998: January—December	12,500	\$42.33	\$1.69
1999: January—December	12,500	\$42.75	\$1.71
2000: January—December	12,500	\$43.50	\$1.74
2001: January—December	12,500	\$44.25	\$1.77
2002: January—December	12,500	\$45.25	\$1.81
2003: January—December	12,500	\$45.75	\$1.83
2004: January—December	12,500	\$46.75	\$1.87
2005: January—December	12,500	\$47.25	\$1.89
2006: January—December	12,500	\$48.50	\$1.94

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1996: January—December	12,500	\$42.50	\$1.70
1997: January—December	12,500	\$42.75	\$1.76
1998: January—December	12,500	\$45.00	\$1.80
1999: January—December	12,500	\$46.75	\$1.87
2000: January—December	12,500	\$47.75	\$1.91
2001: January—December	12,500	\$49.00	\$1.96
2002: January—December	12,500	\$50.25	\$2.01
2003: January—December	12,500	\$51.50	\$2.06
2004: January—December	12,500	\$52.75	\$2.11
2005: January—December	12,500	\$54.00	\$2.16
2006: January—December	12,500	\$55.50	\$2.22

ELECTRIC FUELS CORPORATION
Estimated Delivered Coal Prices — 1998—2016 Forecast
Polk County Site

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$41.65	\$1.78
1999: January—December	2,136	11,700	\$42.12	\$1.80
2000: January—December	2,136	11,700	\$42.59	\$1.82
2001: January—December	2,136	11,700	\$43.06	\$1.84
2002: January—December	2,136	11,700	\$43.76	\$1.87
2003: January—December	2,136	11,700	\$44.46	\$1.90
2004: January—December	2,136	11,700	\$45.16	\$1.93
2005: January—December	2,136	11,700	\$45.63	\$1.95
2006: January—December	2,136	11,700	\$46.57	\$1.99
2007: January—December	2,136	11,700	\$47.03	\$2.01
2008: January—December	2,136	11,700	\$47.50	\$2.03
2009: January—December	2,136	11,700	\$48.44	\$2.07
2010: January—December	2,136	11,700	\$49.37	\$2.11
2011: January—December	2,136	11,700	\$50.31	\$2.15
2012: January—December	2,136	11,700	\$51.25	\$2.19
2013: January—December	2,136	11,700	\$51.95	\$2.22
2014: January—December	2,136	11,700	\$52.65	\$2.25
2015: January—December	2,136	11,700	\$53.35	\$2.28
2016: January—December	2,136	11,700	\$54.05	\$2.31

Note: The coal prices used in the above forecast were derived from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994 and other available market data. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site escalated by an assumed contract escalation package which results in an average 2.0 percent increase per year.

ELECTRIC FUELS CORPORATION
 Estimated Delivered Coal Prices — 1998—2016 Forecast
 Polk County Site — High Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$43.06	\$1.84
1999: January—December	2,136	11,700	\$44.76	\$1.87
2000: January—December	2,136	11,700	\$44.69	\$1.91
2001: January—December	2,136	11,700	\$45.86	\$1.96
2002: January—December	2,136	11,700	\$46.80	\$2.00
2003: January—December	2,136	11,700	\$47.97	\$2.05
2004: January—December	2,136	11,700	\$49.14	\$2.10
2005: January—December	2,136	11,700	\$50.31	\$2.15
2006: January—December	2,136	11,700	\$51.48	\$2.20
2007: January—December	2,136	11,700	\$52.65	\$2.25
2008: January—December	2,136	11,700	\$53.59	\$2.29
2009: January—December	2,136	11,700	\$55.22	\$2.36
2010: January—December	2,136	11,700	\$56.86	\$2.43
2011: January—December	2,136	11,700	\$58.50	\$2.50
2012: January—December	2,136	11,700	\$60.14	\$2.57
2013: January—December	2,136	11,700	\$61.78	\$2.64
2014: January—December	2,136	11,700	\$63.18	\$2.70
2015: January—December	2,136	11,700	\$64.82	\$2.77
2016: January—December	2,136	11,700	\$66.22	\$2.83

Note: The coal prices used in the above forecast were taken from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site.

ELECTRIC FUELS CORPORATION
 Estimated Delivered Coal Prices — 1998—2016 Forecast
 Polk County Site — Low Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$39.54	\$1.69
1999: January—December	2,136	11,700	\$40.01	\$1.71
2000: January—December	2,136	11,700	\$40.25	\$1.72
2001: January—December	2,136	11,700	\$40.38	\$1.73
2002: January—December	2,136	11,700	\$40.70	\$1.74
2003: January—December	2,136	11,700	\$40.52	\$1.76
2004: January—December	2,136	11,700	\$40.52	\$1.76
2005: January—December	2,136	11,700	\$41.34	\$1.77
2006: January—December	2,136	11,700	\$41.75	\$1.78
2007: January—December	2,136	11,700	\$41.96	\$1.79
2008: January—December	2,136	11,700	\$42.17	\$1.80
2009: January—December	2,136	11,700	\$42.82	\$1.83
2010: January—December	2,136	11,700	\$43.52	\$1.86
2011: January—December	2,136	11,700	\$44.23	\$1.89
2012: January—December	2,136	11,700	\$44.23	\$1.91
2013: January—December	2,136	11,700	\$45.40	\$1.94
2014: January—December	2,136	11,700	\$45.95	\$1.96
2015: January—December	2,136	11,700	\$45.63	\$1.95
2016: January—December	2,136	11,700	\$46.80	\$2.00

Note: The coal prices used in the above forecast were taken from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site.

ELECTRIC FUELS CORPORATION
Estimated Delivered Coal Prices — 1998—2016 Forecast
Crystal River Site — High Sulfur

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	6,000	11,700	\$40.72	\$1.74
1999: January—December	6,000	11,700	\$41.18	\$1.76
2000: January—December	6,000	11,700	\$41.65	\$1.78
2001: January—December	6,000	11,700	\$42.12	\$1.80
2002: January—December	6,000	11,700	\$42.82	\$1.83
2003: January—December	6,000	11,700	\$43.52	\$1.86
2004: January—December	6,000	11,700	\$44.23	\$1.89
2005: January—December	6,000	11,700	\$44.69	\$1.91
2006: January—December	6,000	11,700	\$45.63	\$1.95
2007: January—December	6,000	11,700	\$46.10	\$1.97
2008: January—December	6,000	11,700	\$46.57	\$1.99
2009: January—December	6,000	11,700	\$47.50	\$2.03
2010: January—December	6,000	11,700	\$48.44	\$2.07
2011: January—December	6,000	11,700	\$49.37	\$2.11
2012: January—December	6,000	11,700	\$50.31	\$2.15
2013: January—December	6,000	11,700	\$51.01	\$2.18
2014: January—December	6,000	11,700	\$51.71	\$2.21
2015: January—December	6,000	11,700	\$52.42	\$2.24
2016: January—December	6,000	11,700	\$53.12	\$2.27

Note: The coal prices used in the above forecast were derived from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994 and other available market data. Transportation cost estimates are based on estimates developed for Polk County less \$.04/MBtu to reflect the shorter distance and water competition available at Crystal River.

ELECTRIC FUELS CORPORATION
 Estimated Delivered Coal Prices — 1998—2016 Forecast
 Crystal River Site — High Sulfur — High Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	6,000	11,700	\$42.12	\$1.80
1999: January—December	6,000	11,700	\$42.82	\$1.83
2000: January—December	6,000	11,700	\$43.76	\$1.87
2001: January—December	6,000	11,700	\$44.93	\$1.92
2002: January—December	6,000	11,700	\$45.86	\$1.96
2003: January—December	6,000	11,700	\$47.03	\$2.01
2004: January—December	6,000	11,700	\$48.20	\$2.06
2005: January—December	6,000	11,700	\$49.37	\$2.11
2006: January—December	6,000	11,700	\$50.54	\$2.16
2007: January—December	6,000	11,700	\$51.71	\$2.21
2008: January—December	6,000	11,700	\$52.65	\$2.25
2009: January—December	6,000	11,700	\$54.29	\$2.32
2010: January—December	6,000	11,700	\$55.93	\$2.39
2011: January—December	6,000	11,700	\$57.56	\$2.46
2012: January—December	6,000	11,700	\$59.20	\$2.53
2013: January—December	6,000	11,700	\$60.84	\$2.60
2014: January—December	6,000	11,700	\$62.24	\$2.66
2015: January—December	6,000	11,700	\$63.88	\$2.73
2016: January—December	6,000	11,700	\$65.29	\$2.79

Note: The coal prices used in the above forecast were derived from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994 and other available market data. Transportation cost estimates are based on estimates developed for Polk County less an appropriate amount to reflect the shorter distance and water competition available at Crystal River.

ELECTRIC FUELS CORPORATION
 Estimated Delivered Coal Prices — 1998—2016 Forecast
 Crystal River Site — High Sulfur — Low Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	6,000	11,700	\$38.61	\$1.65
1999: January—December	6,000	11,700	\$39.08	\$1.67
2000: January—December	6,000	11,700	\$39.31	\$1.68
2001: January—December	6,000	11,700	\$39.55	\$1.69
2002: January—December	6,000	11,700	\$40.01	\$1.71
2003: January—December	6,000	11,700	\$40.25	\$1.72
2004: January—December	6,000	11,700	\$40.25	\$1.72
2005: January—December	6,000	11,700	\$40.48	\$1.73
2006: January—December	6,000	11,700	\$40.72	\$1.74
2007: January—December	6,000	11,700	\$40.95	\$1.75
2008: January—December	6,000	11,700	\$41.18	\$1.76
2009: January—December	6,000	11,700	\$41.89	\$1.79
2010: January—December	6,000	11,700	\$42.35	\$1.81
2011: January—December	6,000	11,700	\$43.06	\$1.84
2012: January—December	6,000	11,700	\$43.52	\$1.86
2013: January—December	6,000	11,700	\$44.23	\$1.89
2014: January—December	6,000	11,700	\$44.69	\$1.91
2015: January—December	6,000	11,700	\$44.46	\$1.90
2016: January—December	6,000	11,700	\$45.63	\$1.95

Note: The coal prices used in the above forecast were derived from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994 and other available market data. Transportation cost estimates are based on estimates developed for Polk County less an appropriate amount to reflect the shorter distance and water competition available at Crystal River.

FUELS SUPPLY DEPARTMENT
FCP 9501
ORIMULSION - HIGH CASE
\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
			2.46
			2.52
		.61	2.58
		.62	2.63
1999	1.85	.63	2.69
2000	1.90	.63	2.75
2001	1.95	.64	2.80
2002	2.00	.65	
2003	2.05	.65	
2004	2.10		
2005	2.15		

¹ 4.5 million BTU/BBL.

² After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 45% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

FCP9501.1

5/25/95
D. D. Williams

FUELS SUPPLY DEPARTMENT

FCP 9501

FUEL OIL

LOW CASE

Delivered to Florida - West Coast

\$/MMBTU

	<u>#6 - 1.0% S</u>	<u>#6 - 1.5% S</u>	<u>#6 - 2.5% S</u>	<u>#2 - 0.5% S</u>
5/95 - 6/95	2.80	2.77	2.70	4.30
7/95 - 12/95	2.40	2.33	2.20	4.00
1996	2.00	1.93	1.80	3.70
1997	2.04	1.97	1.84	3.77
1998	2.08	2.01	1.88	3.85
1999	2.12	2.05	1.92	3.93
2000	2.16	2.09	1.96	4.00
2001	2.20	2.13	2.00	4.08
2002	2.24	2.17	2.02	4.17
2003	2.28	2.20	2.04	4.25
2004	2.32	2.23	2.06	4.34
2005	2.36	2.27	2.08	4.42

Escalate at 85% of inflation after 2005

FUELS SUPPLY DEPARTMENT

FCP 9501

NATURAL GAS SUPPLY*

LOW CASE

\$/MMBTU

	<u>Supply Cost</u>
1996	1.60
1997	1.62
1998	1.64
1999	1.66
2000	1.68
2001	1.70
2002	1.74
2003	1.78
2004	1.82
2005	1.86

Escalate at 85% of inflation after 2005

- * Transportation cost assumed to be the same as in the Base Case and should be added for each delivery point.

FUELS SUPPLY DEPARTMENT

FCP 9501

ORIMULSION - LOW CASE

\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
1999	1.65	.41	2.06
2000	1.67	.42	2.09
2001	1.71	.43	2.14
2002	1.74	.43	2.17
2003	1.78	.44	2.22
2004	1.81	.45	2.26
2005	1.85	.45	2.30

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 45% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

FUELS SUPPLY DEPARTMENT

FCP 9501

PETROLEUM COKE

LOW CASE

\$/MMBTU

CRYSTAL RIVER		INLAND FREIGHT	POLK COUNTY
1996	.95	.20	1.15
1997	.97	.20	1.17
1998	.99	.21	1.20
1999	1.01	.22	1.23
2000	1.03	.23	1.26
2001	1.05	.24	1.29
2002	1.07	.25	1.32
2003	1.09	.26	1.35
2004	1.11	.27	1.38
2005	1.13	.28	1.41

- ▣ Market price from various suppliers plus EFC freight to Crystal River. Inland Freight based on estimated truck freight.
- ▣ Escalate at 85% of inflation after 2005.
- ▣ 14,000 BTU/lb.

FUELS SUPPLY DEPARTMENT
FCP 9501
FUEL OIL
HIGH CASE
Delivered to Florida - West Coast
\$/MMBTU

	<u>#6 - 1.0% S</u>	<u>#6 - 1.5% S</u>	<u>#6 - 2.5% S</u>	<u>#2 - 0.5% S</u>
5/95 - 6/95	3.00	2.98	2.95	4.50
1996	3.05	3.03	3.00	4.60
1997	3.10	3.08	3.05	4.70
1998	3.15	3.13	3.10	4.80
1999	3.20	3.18	3.15	4.90
2000	3.30	3.27	3.20	5.10
2001	3.50	3.43	3.30	5.30
2002	3.70	3.60	3.40	5.50
2003	3.90	3.78	3.55	5.70
2004	4.10	3.97	3.70	5.90
2005	4.30	4.17	3.90	6.10

Escalate at inflation after 2005

FUELS SUPPLY DEPARTMENT
FCP 9501
NATURAL GAS SUPPLY*
HIGH CASE
\$/MMBTU

	<u>Supply Cost</u>
	2.20
1996	2.30
1997	2.40
1998	2.50
1999	2.70
2000	2.90
2001	3.10
2002	3.30
2003	3.50
2004	3.70
2005	

Escalate at inflation after 2005

- * Transportation cost assumed to be the same as in the Base Case and should be added for each delivery point.

5/25/95
D. D. Williams

FCP9501.1

FUELS SUPPLY DEPARTMENT**FCP 9501****PETROLEUM COKE****HIGH CASE****\$/MMBTU****CRYSTAL RIVER****INLAND FREIGHT****POLK COUNTY**

1996	1.25		
1997	1.30	.40	1.65
1998	1.35	.40	1.70
1999	1.40	.41	1.76
2000	1.45	.42	1.82
2001	1.50	.43	1.88
2002	1.55	.44	1.99
2003	1.60	.45	2.00
2004	1.65	.46	2.06
2005	1.70	.47	2.12
		.48	2.18

- ▣ Market price from various suppliers plus EFC freight to Crystal River. Inland Freight based on estimated truck freight.
- ▣ Escalate at inflation after 2005.
- ▣ 14,000 BTU/lb.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

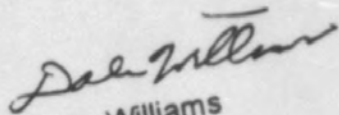
231-4532
TELEPHONE

SUBJECT: Fuel Cost Projections

DATE: November 30, 1994

TO: Mr. R. D. Niekum
Mr. K. H. Wieland

Please find attached an addition to FCP 9403 for Nuclear Fuel Expense.
If you have any questions or require additional information, please advise.


Dale Williams

Attachments:

cc: L. D. Brousseau
N. L. Davis
R. D. Dolan
D. G. Edwards
M. B. Foley
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
M. D. Rib
J. R. Rocha
D. M. OShea
P. E. Toomey/L. G. Schuster
File
Forecast Book

COMPANY CONFIDENTIAL

FUELS SUPPLY DEPARTMENT
FPC 9403
NUCLEAR FUEL EXPENSE PROJECTIONS

¢/MMBTU's

through 3/96: 38

- Does not include spent fuel disposal charges or enrichment plant decommissioning charges.
- Escalate future cycles with inflation.
- Provided by Nuclear Operations.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

F - Forecast

SUBJECT: **Fuel Cost Projections**

DATE: **November 25, 1994**

TO: **Mr. R. D. Niekum
Mr. K. H. Wieland**

Please find attached FCP 9403 which is a short term update (though 3/96) for the April 1995 through September 1995 Fuel Adjustment Forecast.

If you have any questions or require additional information, please advise.

Dale Williams
Dale Williams

Attachments:

cc: L. D. Brousseau
N. L. Davis
R. D. Dolan
D. G. Edwards
M. B. Foley
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
M. D. Rib
J. R. Rocha
P. E. Toomey/L. G. Schuster
File
Forecast Book

COMPANY CONFIDENTIAL

FUELS SUPPLY DEPARTMENT

FPC 9403

NATURAL GAS

\$/MMBTU

<u>Univ of Fla</u>	<u>Supply Cost¹</u>	<u>Univ of Fla Transport</u>		<u>Total Cost³</u>
		<u>Var</u>	<u>Fixed²</u>	
11/93 - 3/96	1.92	.26	.44	2.62

<u>Suwannee</u>	<u>Supply Cost¹</u>	<u>Suwannee Transport</u>		<u>Total Cost³</u>
		<u>Var</u>	<u>Fixed²</u>	
11/93 - 3/96	1.88	.12	.69	2.69

¹ 1,000 BTU/CF

² Fixed cost for Univ of Fla based on 9,300 MMBTU/day
Fixed cost for Suwannee based on 10,000 MMBTU/day

³ 100% Load Factor

COMPANY CONFIDENTIAL

FUELS SUPPLY DEPARTMENT

FCP 9403

RESIDUAL FUEL OIL - #6¹

DELIVERED TO FLORIDA

\$/MMBTU

1.0% Sulfur²

11/93 - 3/96

2.60

1.5% Sulfur³

2.50

2.5% Sulfur⁴

2.30

LIGHT FUEL OIL - #2⁵
DELIVERED TO FLORIDA

\$/MMBTU

.5% SULFUR

11/93 - 3/96

4.30

- 1 6.4 MMBTU/BBL - Low API
- 2 Suwannee 3 (If N. Gas isn't available)
- 3 Ancote
- 4 Bartow and Suwannee
- 5 5.8 MMBTU/BBL

11/17/94
D. D. Williams

FCP9403 NEW

COMPANY CONFIDENTIAL

FUELS SUPPLY DEPARTMENT
FCP 9403
OIL TRANSPORTATION COST
\$/MMBTU

1995

Residual Fuel Oil

Suwannee .65¹

Light Fuel Oil

Anclote	.11
Avon Park	.19
Bartow/Bayboro	.16
Crystal River	.19
Debary	.24
Higgins	.09
Intercession City ²	.14
Port St. Joe	.52
Rio Pinar	.22
Suwannee	.23
Turner	.23

¹ Based on minimum volume of 100,000 BBLS/yr.

² Add \$24,000/month for dedicated storage in Tampa

FUELS SUPPLY DEPARTMENT

FCP 9403

FUEL INVENTORY TARGET LEVELS¹

	<u>INVENTORY w/o TANK BOTTOMS</u>	<u>TANK BOTTOMS</u>	<u>TOTAL INVENTORY</u>
RESIDUAL OIL (#6) BBLs.			
	240,000	138,346	378,346
Ancote & Bartow South	200,000	63,214	263,214
Bartow & Bartow North	20,000	12,088	32,088
Suwannee 2.5%	<u>10,000</u>	<u>8,192</u>	<u>18,192</u>
Suwannee 1.0%			691,840
	470,000	221,840	
TOTAL			
LIGHT OIL (#2) BBLs.			
	7,000	546	7,546
Avon Park	28,440	6,762	35,202
Bartow	25,000	6,522	31,522
Bayboro	65,721	34,279	100,000
Debary	12,000	1,983	13,983
Higgins	87,000	32,037	119,037
Intercession City	1,350	226	1,576
Port St. Joe	1,350	124	1,474
Rio Pinar	24,000	10,338	34,338
Suwannee	25,000	6,538	31,538
Turner	<u>19,742</u>	<u>3,749</u>	<u>23,491</u>
Start-up ²			399,707
	296,603	103,104	
TOTAL			

¹ Coal based on delivery schedules

² Ancote and Crystal River



ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733. (813) 824-6600

November 22, 1994

Mr. Dale D. Williams
Principal Fuel Buyer
FLORIDA POWER CORPORATION
P. O. Box 14042
St. Petersburg, Florida 33733

Dear Dale:

Attached are the January 1995 to March 1996 coal-price forecasts for Crystal River Units 1 & 2 (Attachment A), Crystal River Units 4 & 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your April - September 1995 fuel-adjustment filing. We have based our calculations on the latest financial estimates for 1995 provided by our Accounting Department, and the assumptions listed on Appendix I.

If you require additional information, please call me or Donna Davis.

Sincerely,

ELECTRIC FUELS CORPORATION

Raynia A. Hemmer
Contract Administration Specialist

RAH:jss
Attachments

cc: W. D. Carter
D. J. Clark, Jr.
D. G. Edwards
D. M. Davis
G. K. Orchard

ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST

CRYSTAL RIVER 1 & 2

	Tons (000s)	Btu/lb.	\$/Ton	Average ¢/MMBtu	Incremental ¢/MMBtu
<u>1995</u>					
January	133	12,553	45.98	183.15	165.56
February	133	12,553	45.99	183.18	165.04
March	134	12,553	45.97	183.12	165.04
April	133	12,553	46.04	183.40	165.52
May	133	12,553	46.04	183.39	165.52
June	134	12,553	46.21	184.05	165.52
July	133	12,553	46.19	183.99	166.01
August	134	12,553	46.19	183.99	166.01
September	134	12,553	46.20	184.02	166.01
October	133	12,552	46.33	184.55	166.49
November	133	12,552	46.33	184.55	166.49
December	133	12,552	46.47	185.12	166.49
<u>1996</u>					
January	146	12,643	44.16	174.66	169.43
February	146	12,643	44.16	174.66	169.43
March	146	12,643	44.16	174.66	169.43

ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST
CRYSTAL RIVER 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu	Incremental c/MMBtu
<u>1995</u>					
January	292	12,619	49.48	196.06	172.96
February	291	12,620	49.48	196.04	172.44
March	292	12,620	49.49	196.10	172.44
April	292	12,620	49.54	196.27	172.92
May	291	12,619	49.53	196.26	172.92
June	292	12,620	49.34	195.49	172.92
July	292	12,620	49.25	195.12	173.41
August	291	12,620	49.28	195.24	173.41
September	292	12,620	49.26	195.18	173.41
October	292	12,620	49.38	195.66	173.89
November	291	12,620	49.39	195.68	173.89
December	292	12,620	49.54	196.27	173.89
<u>1996</u>					
January	292	12,616	51.63	204.63	175.95
February	291	12,616	51.63	204.63	175.95
March	292	12,616	51.63	204.63	175.95

ELECTRIC FUELS CORPORATION
1995 AND 1996 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2 and 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu
<u>1995</u>				
January	425	12,598	48.38	192.02
February	424	12,599	48.38	192.02
March	426	12,599	48.39	192.04
April	425	12,599	48.44	192.25
May	424	12,598	48.44	192.24
June	426	12,599	48.36	191.91
July	425	12,599	48.29	191.64
August	425	12,599	48.31	191.72
September	426	12,599	48.30	191.69
October	425	12,599	48.43	192.19
November	424	12,599	48.43	192.20
December	425	12,599	48.58	192.79
<u>1996</u>				
January	438	12,625	49.14	194.63
February	437	12,625	49.14	194.63
March	438	12,625	49.14	194.63



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS APRIL 1, 1995 - SEPTEMBER 30, 1995

Page 1 of 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE AS OF OCTOBER 1994, AND 1993 ANNUAL PERCENT CHANGES. THE FLORIDA PROGRESS CORPORATE ANNUAL PROFIT PLAN (THE PLAN) INFLATION ASSUMPTION OF 3.5% FOR 1995 AND 1996 (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- ONE CR 1 & 2 COAL CONTRACT OF 850,000 TONS EXPIRES DECEMBER 31, 1994, AND IS REPLACED WITH A NEW 500,000-TON COAL CONTRACT. THREE CR 1 & 2 CONTRACTS, TOTALING 800,000 TONS, EXPIRE BY THE END OF 1995, AND FORECASTED REPLACEMENT IS WITH TWO 300,000-TON COAL CONTRACTS IN 1996. TWO CR 4 & 5 CONTRACTS REFLECT MARKET REOPENER PRICES IN JANUARY 1995. NO MARKET REOPENERS ARE APPLICABLE IN 1996.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET-PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S (EFC'S COAL-INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL-MARKET INTELLIGENCE.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT THE PLAN INFLATION ASSUMPTION OF 3.5% FOR 1995 AND 1996 (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT TWO SETS OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF FEBRUARY 1, 1995, AND FEBRUARY 1, 1996, RESPECTIVELY, AT A COST PER SET OF APPROXIMATELY \$4.2 MILLION.
- 1995 AND 1996 WATER FREIGHT IS ESTIMATED AT THE CURRENT MARKET RATE ESCALATED AT THE FORECASTED ESCALATION OF THE INDIVIDUAL INDICES, IN ACCORDANCE WITH ESCALATION PROVISIONS OF THE WATERBORNE COMPONENT.



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS APRIL 1, 1995 - SEPTEMBER 30, 1995

Page 2 of 2

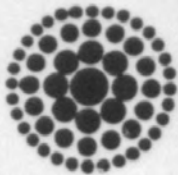
GENERAL ADMINISTRATION

- COSTS ARE BASED ON THE 1995 ANNUAL PROFIT PLAN.
- 37 PERCENT EFFECTIVE TAX RATE IS ASSUMED FOR INCOME-TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON EFC'S 1995 ANNUAL PROFIT PLAN, WHICH REFLECTED A TOTAL REQUIREMENT OF 5,100,000 TONS FOR 1995, AND 5,250,000 TONS FOR 1996.
- 1995 CONTRACT TONNAGE INCLUDES 147,000 TONS DEFERRED FROM 1994 TO 1995.

EFC/RAH
11/22/94



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

SUBJECT: **Fuel Cost Projections**

TO: **Mr. R. D. Niekum**
Mr. K. H. Wieland

*F
Forecast*
DATE: **November 21, 1994**

Please find attached a revision to FCP 9402 Base and Low Orimulsion cost. This corrects an error in the assumed escalation rate on scrubber cost after 2005.

If you have any questions or require additional information, please advise.

Dale D. Williams
Dale D. Williams

Attachments:

cc: L. D. Brousseau
N. L. Davis
R. D. Dolan
D. G. Edwards
M. B. Foley
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
M. D. Rib
J. R. Rocha
P. E. Toomey/L. G. Schuster
File
Forecast Book

FUELS SUPPLY DEPARTMENT
FCP 9402 - LOW SCENARIO (Revised 11/21/94)
ORIMULSION
\$/MMBTU¹

		<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
1999		1.65		
2000		1.68	.41	2.06
2001		1.71	.42	2.10
2002		1.74	.43	2.14
2003		1.77	.43	2.17
2004		1.80	.44	2.21
2005	5.8	1.83	.45	2.25
6	2.8	1.86	.45	2.28
7	2.8	1.90		
8				
9				
10				
11				
12				
13				
14				
15				
16				

$$i = 2.8 \times .67 = 1.88$$

$$1.83 \times 1.0188 = 1.8644$$

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 45% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

FUELS SUPPLY DEPARTMENT

FCP 9402 (Revised 11/21/94)

ORIMULSION - BASE CASE

\$/MMBTU¹

ORIMULSION²

SCRUBBER CHARGE³

TOTAL⁴

1999	1.65	.41	2.06
2000	1.70	.42	2.12
2001	1.74	.43	2.17
2002	1.78	.43	2.21
2003	1.81	.44	2.25
2004	1.84	.45	2.29
2005	1.87	.45	2.32

6	2.8	1.91	.46	2.37
7		1.95	.47	2.42
8		1.97	.48	2.45
9		2.01	.49	2.50
10	2.5	2.04	.50	2.54
11		2.08	.51	2.59
12		2.12	.52	2.64
13		2.16	.53	2.69
14	2.5	2.20	.54	2.74
15		2.24	.55	2.79
16		2.28	.57	2.85

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal. After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF. After 2005 escalate 45% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

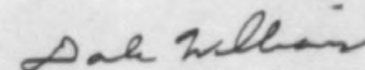
SUBJECT: **Fuel Cost Projections**

TO: **Mr. R. D. Niekum**
Mr. K. H. Wieland

DATE: **November 16, 1994**

Please find attached a letter from Ms. Donna Davis of EFC which contains a forecast of incremental coal prices based on the reduced tonnage amounts listed. Also attached are the average prices mentioned in the letter. This forecast is for comparison with the base case FCP 9402 to estimate the impacts of reduced tonnage on coal cost.

If you have any questions or require additional information, please advise.


Dale D. Williams

Attachments:

cc: N. L. Davis
D. G. Edwards/Donna Davis
M. B. Foley
R. W. Lehnhoff
D. E. Schleicher
W. C. Micklon
M. D. Rib
P. E. Toomey/L. G. Schuster
File
Forecast Book



ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

November 10, 1994

Mr. Dale D. Williams
Fuel and Special Projects
FLORIDA POWER CORPORATION - H2A
3201 - 34th Street South
St. Petersburg, FL 33711

Subject: Incremental Pricing - Case I

Dear Dale:

Per your request, attached are the 1998-2007 Estimated Incremental Coal Prices for Case I. The tons and average prices for this case were provided to Lee Schuster by Dennis Edwards on November 1, 1994, which I understand were provided to you by Lee.

If you have any questions or require additional information on this matter, please let me know.

Sincerely,

ELECTRIC FUELS CORPORATION

Donna M. Davis

Donna M. Davis
Manager Regulatory Analysis

DMD:lp

Attachments

cc: D. G. Edwards
R. A. Hemmer
D. J. Clark
G. K. Orchard

ELECTRIC FUELS CORPORATION
Estimated Incremental Coal Prices
1998-2007

Case I

Crystal River 1 & 2

Year	Btu/lb	\$/Ton	Average \$/MBtu
1998: January—December	12,500	\$44.41	\$1.78
1999: January—December	12,500	\$46.10	\$1.84
2000: January—December	12,500	\$47.37	\$1.89
2001: January—December	12,500	\$48.79	\$1.95
2002: January—December	12,500	\$49.44	\$1.98
2003: January—December	12,500	\$49.47	\$1.98
2004: January—December	12,500	\$50.85	\$2.03
2005: January—December	12,500	\$52.28	\$2.09
2006: January—December	12,500	\$53.02	\$2.12
2007: January—December	12,500	\$54.49	\$2.18

Crystal River 4 & 5

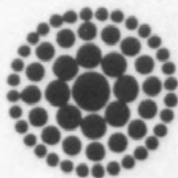
Year	Btu/lb	\$/Ton	Average \$/MBtu
1998: January—December	12,500	\$47.09	\$1.88
1999: January—December	12,500	\$49.21	\$1.97
2000: January—December	12,500	\$50.75	\$2.03
2001: January—December	12,500	\$52.43	\$2.10
2002: January—December	12,500	\$53.33	\$2.13
2003: January—December	12,500	\$53.67	\$2.15
2004: January—December	12,500	\$55.27	\$2.21
2005: January—December	12,500	\$56.92	\$2.28
2006: January—December	12,500	\$57.94	\$2.32
2007: January—December	12,500	\$59.64	\$2.39

EFC/DMD—11/10/94

ELECTRIC FUELS CORP
FPC Fuel Price Forecasts
1998 - 2007 Forecast

ELECTRIC FUELS CORP
FPC Fuel Price Forecasts
1998 - 2007 Forecast

[illegible]



**Florida
Power**
CORPORATION

F - Forecasts

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

SUBJECT: **Fuel Cost Projections**

DATE: **October 27, 1994**

TO: **Mr. R. D. Niekum
Mr. K. H. Wieland**

Please find attached a letter from Mr. Dennis Edwards of EFC updating their high and low forecast of coal prices. A high and low scenario forecast for natural gas, oil and orimulsion is also enclosed. In addition, a revised base case forecast for orimulsion is enclosed to correspond to the revised coal forecast provided on 10/20/94.

Please note that except for the orimulsion base case revision, included in this package, the remainder of the base case FCP 9402 remains unchanged since the 10/20/94 coal price revision.

If you have any questions or require additional information, please advise.

Dale D. Williams
Dale D. Williams

Attachments:

cc: L. D. Brousseau
N. L. Davis
R. D. Dolan
D. G. Edwards
M. B. Foley
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
M. D. Rib
J. R. Rocha
P. E. Toomey/L. G. Schuster
File
Forecast Book

ELECTRIC FUELS CORPORATION

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

October 20, 1994

Mr. Dale D. Williams
Fuel and Special Projects—H2A
Florida Power Corporation
Post Office Box 14042
St. Petersburg, Florida 33733

Subject: Supplemental Budget Information

Dear Mr. Williams:

This letter is further to my October 17, 1994 letter to you regarding updated coal price forecasts for Crystal River 1 & 2 and 4 & 5 for the period of 1995 through 2005. While my October 17, 1994 letter contained the "base case" forecast, I indicated that the "high" and "low" case information you requested would require additional time to compile. This work is now complete and these cases are attached.

Attachments H-A and H-B reflect our "high case" results with the following assumptions:

- 1) Inflation at 5 percent.
- 2) Spot prices \$1/ton over base case.
- 3) New contract/reopener prices \$1/ton over base case.
- 4) A 250,000 ton reduction in spot "D" water coal.

Attachments L-A and L-B reflect the results of our "low case" modeling using the following assumptions:

- 1) Inflation at 3 percent.
- 2) Spot prices \$.50/ton under base case.
- 3) New contract/reopener prices \$.50/ton under base case.
- 4) A 250,000 ton (125,000 each of "A" and "D") increase in spot rail coal.

Like our "base case" forecast, the high and low case forecasts are for the period 1995 through 2005. We recommend that prices beyond 2005 should be trended with inflation, adjusted in accordance with the assumptions listed above times a .67 multiplier.

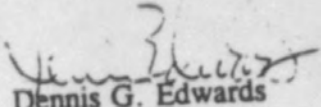
Mr. Dale D. Williams
October 20, 1994
Page 2

Supplemental Budget Information

The Polk County Site forecasts (H-C and L-C) have been adjusted only by the change in our inflation assumptions.

If you have any questions on this supplemental information or anything previously supplied regarding our forecasts, please do not hesitate to let me know.

Sincerely,


Dennis G. Edwards
Vice President
Coal Procurement

DGE/rao

Attachments

cc/att: Mr. W. D. Carter
Mrs. D. M. Davis
Mr. G. K. Orchard
Mrs. R. A. Hemmer

ELECTRIC FUELS CORPORATION

Estimated Coal Prices
1995-2005

Attachment H-A

High Case *Crystal River 1 & 2*

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January-December	1,600	12,396	\$46.73	\$1.88
1996: January-December	1,750	12,500	\$45.34	\$1.81
1997: January-December	1,750	12,500	\$46.83	\$1.87
1998: January-December	1,750	12,500	\$48.34	\$1.93
1999: January-December	1,700	12,500	\$50.13	\$2.00
2000: January-December	1,700	12,500	\$51.75	\$2.07
2001: January-December	1,700	12,500	\$53.50	\$2.14
2002: January-December	1,700	12,500	\$55.25	\$2.21
2003: January-December	1,700	12,500	\$57.00	\$2.28
2004: January-December	1,700	12,500	\$58.75	\$2.35
2005: January-December	1,700	12,500	\$60.50	\$2.42

Crystal River 4 & 5

<i>Year</i>	<i>Tons (000s)</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January-December	3,250	12,668	\$50.65	\$2.00
1996: January-December	3,250	12,664	\$53.48	\$2.11
1997: January-December	3,250	12,664	\$55.08	\$2.17
1998: January-December	3,250	12,664	\$56.11	\$2.22
1999: January-December	3,250	12,669	\$57.86	\$2.28
2000: January-December	3,250	12,669	\$59.08	\$2.34
2001: January-December	3,250	12,669	\$60.59	\$2.40
2002: January-December	3,250	12,669	\$62.11	\$2.46
2003: January-December	3,250	12,669	\$63.62	\$2.52
2004: January-December	3,250	12,669	\$65.13	\$2.58
2005: January-December	3,250	12,669	\$66.65	\$2.64

Crystal River 1 & 2 and 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January-December	12,578	\$49.36	\$1.96
1996: January-December	12,606	\$50.63	\$2.01
1997: January-December	12,606	\$52.19	\$2.07
1998: January-December	12,606	\$53.39	\$2.12
1999: January-December	12,611	\$55.21	\$2.19
2000: January-December	12,611	\$56.62	\$2.25
2001: January-December	12,611	\$58.13	\$2.31
2002: January-December	12,611	\$59.64	\$2.37
2003: January-December	12,611	\$61.41	\$2.44
2004: January-December	12,611	\$62.92	\$2.50
2005: January-December	12,611	\$64.42	\$2.56

ELECTRIC FUELS CORPORATION

Estimated Incremental Coal Prices

1995—2005

*High Case**Crystal River 1 & 2*

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$42.50	\$1.70
1996: January—December	12,500	\$43.75	\$1.75
1997: January—December	12,500	\$44.75	\$1.79
1998: January—December	12,500	\$46.00	\$1.84
1999: January—December	12,500	\$47.25	\$1.89
2000: January—December	12,500	\$48.50	\$1.94
2001: January—December	12,500	\$49.75	\$1.99
2002: January—December	12,500	\$51.00	\$2.04
2003: January—December	12,500	\$52.25	\$2.09
2004: January—December	12,500	\$53.50	\$2.14
2005: January—December	12,500	\$54.75	\$2.19

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$44.50	\$1.78
1996: January—December	12,500	\$45.25	\$1.81
1997: January—December	12,500	\$47.00	\$1.88
1998: January—December	12,500	\$48.50	\$1.94
1999: January—December	12,500	\$50.25	\$2.01
2000: January—December	12,500	\$52.00	\$2.08
2001: January—December	12,500	\$53.50	\$2.14
2002: January—December	12,500	\$55.25	\$2.21
2003: January—December	12,500	\$56.75	\$2.27
2004: January—December	12,500	\$58.50	\$2.34
2005: January—December	12,500	\$60.00	\$2.40

ELECTRIC FUELS CORPORATION
Estimated Delivered Coal Prices — 1998—2016 Forecast
Polk County Site — High Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$43.62	\$1.86
1999: January—December	2,136	11,700	\$44.23	\$1.89
2000: January—December	2,136	11,700	\$45.25	\$1.93
2001: January—December	2,136	11,700	\$46.27	\$1.98
2002: January—December	2,136	11,700	\$47.30	\$2.02
2003: January—December	2,136	11,700	\$48.50	\$2.07
2004: January—December	2,136	11,700	\$49.61	\$2.12
2005: January—December	2,136	11,700	\$50.74	\$2.17
2006: January—December	2,136	11,700	\$51.87	\$2.22
2007: January—December	2,136	11,700	\$53.02	\$2.27
2008: January—December	2,136	11,700	\$54.17	\$2.31
2009: January—December	2,136	11,700	\$55.77	\$2.38
2010: January—December	2,136	11,700	\$57.39	\$2.45
2011: January—December	2,136	11,700	\$59.02	\$2.52
2012: January—December	2,136	11,700	\$60.65	\$2.59
2013: January—December	2,136	11,700	\$62.30	\$2.66
2014: January—December	2,136	11,700	\$63.73	\$2.72
2015: January—December	2,136	11,700	\$65.17	\$2.79
2016: January—December	2,136	11,700	\$66.63	\$2.85

Note: The coal prices used in the above forecast were taken from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site escalated by an assumed contract escalation package which results in an average 2.0 percent increase per year.

ELECTRIC FUELS CORPORATION

Estimated Coal Prices

1995-2005

Attachment L-A

Low Case

Crystal River 1 & 2

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	1,725	12,404		
1996: January-December	1,875	12,500	\$45.01	\$1.81
1997: January-December	1,875	12,500	\$42.85	\$1.71
1998: January-December	1,875	12,500	\$43.75	\$1.75
1999: January-December	1,825	12,500	\$44.62	\$1.78
2000: January-December	1,825	12,500	\$45.70	\$1.83
2001: January-December	1,825	12,500	\$46.75	\$1.87
2002: January-December	1,825	12,500	\$47.75	\$1.91
2003: January-December	1,825	12,500	\$48.75	\$1.95
2004: January-December	1,825	12,500	\$49.75	\$1.99
2005: January-December	1,825	12,500	\$50.75	\$2.03
			\$51.75	\$2.07

Crystal River 4 & 5

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	3,625	12,615		
1996: January-December	3,625	12,612	\$48.68	\$1.93
1997: January-December	3,625	12,612	\$50.63	\$2.01
1998: January-December	3,625	12,612	\$51.49	\$2.04
1999: January-December	3,625	12,619	\$52.24	\$2.07
2000: January-December	3,625	12,619	\$53.20	\$2.11
2001: January-December	3,625	12,619	\$54.26	\$2.15
2002: January-December	3,625	12,619	\$55.27	\$2.19
2003: January-December	3,625	12,619	\$56.28	\$2.23
2004: January-December	3,625	12,619	\$57.29	\$2.27
2005: January-December	3,625	12,619	\$58.30	\$2.31
			\$59.31	\$2.35

Crystal River 1 & 2 and 4 & 5

Year	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	5,350		
1996: January-December	5,500	\$47.49	\$1.89
1997: January-December	5,500	\$47.98	\$1.91
1998: January-December	5,500	\$48.85	\$1.94
1999: January-December	5,450	\$49.65	\$1.97
2000: January-December	5,450	\$50.69	\$2.01
2001: January-December	5,450	\$51.75	\$2.06
2002: January-December	5,450	\$52.75	\$2.10
2003: January-December	5,450	\$53.76	\$2.14
2004: January-December	5,450	\$54.77	\$2.18
2005: January-December	5,450	\$55.77	\$2.22
		\$56.86	\$2.26

ELECTRIC FUELS CORPORATION
 Estimated Incremental Coal Prices
 1995—2005

Low Case

Crystal River 1 & 2

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$40.69	\$1.63
1996: January—December	12,500	\$41.54	\$1.66
1997: January—December	12,500	\$42.33	\$1.69
1998: January—December	12,500	\$43.14	\$1.73
1999: January—December	12,500	\$44.09	\$1.76
2000: January—December	12,500	\$44.75	\$1.79
2001: January—December	12,500	\$45.50	\$1.82
2002: January—December	12,500	\$46.25	\$1.85
2003: January—December	12,500	\$47.00	\$1.88
2004: January—December	12,500	\$47.75	\$1.91
2005: January—December	12,500	\$48.50	\$1.94

Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$42.57	\$1.70
1996: January—December	12,500	\$43.19	\$1.73
1997: January—December	12,500	\$44.48	\$1.78
1998: January—December	12,500	\$45.79	\$1.83
1999: January—December	12,500	\$47.24	\$1.89
2000: January—December	12,500	\$48.50	\$1.94
2001: January—December	12,500	\$49.75	\$1.99
2002: January—December	12,500	\$51.00	\$2.04
2003: January—December	12,500	\$52.25	\$2.09
2004: January—December	12,500	\$53.50	\$2.14
2005: January—December	12,500	\$54.75	\$2.19

ELECTRIC FUELS CORPORATION
Estimated Delivered Coal Prices — 1998—2016 Forecast
Polk County Site — Low Case

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$40.06	\$1.71
1999: January—December	2,136	11,700	\$40.38	\$1.73
2000: January—December	2,136	11,700	\$40.70	\$1.74
2001: January—December	2,136	11,700	\$41.02	\$1.75
2002: January—December	2,136	11,700	\$41.34	\$1.77
2003: January—December	2,136	11,700	\$41.56	\$1.78
2004: January—December	2,136	11,700	\$41.75	\$1.78
2005: January—December	2,136	11,700	\$41.96	\$1.79
2006: January—December	2,136	11,700	\$42.17	\$1.80
2007: January—December	2,136	11,700	\$42.39	\$1.81
2008: January—December	2,136	11,700	\$42.61	\$1.82
2009: January—December	2,136	11,700	\$43.25	\$1.85
2010: January—December	2,136	11,700	\$43.91	\$1.88
2011: January—December	2,136	11,700	\$44.58	\$1.91
2012: January—December	2,136	11,700	\$45.25	\$1.93
2013: January—December	2,136	11,700	\$45.95	\$1.96
2014: January—December	2,136	11,700	\$46.36	\$1.98
2015: January—December	2,136	11,700	\$46.25	\$1.97
2016: January—December	2,136	11,700	\$47.22	\$2.02

Note: The coal prices used in the above forecast were taken from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site escalated by an assumed contract escalation package which results in an average 2.0 percent increase per year.

FUELS SUPPLY DEPARTMENT
FCP 9402 (Revised 10/24/94)
ORIMULSION - BASE CASE
\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
		.41	2.06
1999	1.65	.42	2.12
2000	1.70	.43	2.17
2001	1.74	.43	2.21
2002	1.78	.44	2.25
2003	1.81	.45	2.29
2004	1.84	.45	2.32
2005	1.87		

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 90% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

FUELS SUPPLY DEPARTMENT
FCP 9402 - LOW SCENARIO
NATURAL GAS
DELIVERED ANCLOTE/POLK COUNTY
\$/MMBTU

	HENRY HUB	SUNSHINE			FGT (Phase III)		
	N. Gas	Variable Transport	Fixed Demand	Total*	Variable Transport	Fixed Demand	Total*
1998 - 2005	1.70	.09	.71	2.50	.11	.75	2.56
2006	1.73	.09	.71	2.53	.11	.75	2.59
2007	1.77	.10	.71	2.58	.12	.75	2.64
2008	1.80	.10	.71	2.61	.12	.75	2.67
2009	1.84	.10	.71	2.65	.12	.75	2.71
2010	1.88	.10	.71	2.69	.12	.75	2.75
2011	1.91	.10	.71	2.72	.12	.75	2.78
2012	1.95	.10	.71	2.76	.12	.75	2.82
2013	1.99	.10	.71	2.80	.12	.75	2.86
2014	2.03	.10	.71	2.84	.12	.75	2.90
2015	2.07	.10	.71	2.88	.12	.75	2.94
2016	2.11	.10	.71	2.92	.12	.75	2.98

Premises

- Overall inflation does not impact prices until after 2005, due to continued adequate supply and ongoing technological improvements. The prices rise at about 2%/yr thereafter.
- Competition with fuel oil and other energy providers also keeps pipeline rates stable.
- 1,000 BTU/CF.
- Total cost based on 100% load factor.

FUELS SUPPLY DEPARTMENT
FCP 3402 - LOW SCENARIO
NATURAL GAS
DELIVERED UNIVERSITY OF FLORIDA
\$/MMBTU

FGT - FTS-1 + GRU

	HENRY HUB N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
1995 - 2005	1.70	.17	.37	2.24
2006	1.73	.18	.37	2.28
2007	1.77	.18	.37	2.32
2008	1.80	.18	.37	2.35
2009	1.84	.18	.37	2.39
2010	1.88	.18	.37	2.43
2011	1.91	.18	.37	2.46
2012	1.95	.18	.37	2.50
2013	1.99	.18	.37	2.54
2014	2.03	.18	.37	2.58
2015	2.07	.18	.37	2.62
2016	2.11	.18	.37	2.66

* Assumes 100% load factor and that current rate surcharges are eliminated (also see notes on Anclote/Polk County Natural Gas Premises).

FUELS SUPPLY DEPARTMENT
FCP 9402 - LOW SCENARIO
NATURAL GAS
DELIVERED SUWANNEE PLANT
\$/MMBTU

	HENRY			
	HUB			
	N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
1995 - 2005	1.70	.08	.57	2.35
2006	1.73	.09	.57	2.39
2007	1.77	.09	.57	2.43
2008	1.80	.09	.57	2.46
2009	1.84	.09	.57	2.50
2010	1.88	.09	.57	2.54
2011	1.91	.09	.57	2.57
2012	1.95	.09	.57	2.61
2013	1.99	.09	.57	2.65
2014	2.03	.09	.57	2.69
2015	2.07	.09	.57	2.73
2016	2.11	.09	.57	2.77

* Assumes 100% load factor and that current rate surcharges are eliminated (also see notes on Ancilote/Polk County Natural Gas Premises).

FUELS SUPPLY DEPARTMENT
FCP 9402 - LOW SCENARIO
RESIDUAL FUEL OIL
DELIVERED BARTOW/ANCLOTE
\$/MMBTU

	2.5%	1.0%
1995 - 2005	1.75	2.00
2006	1.79	2.04
2007	1.82	2.08
2008	1.86	2.12
2009	1.89	2.16
2010	1.93	2.20
2011	1.97	2.25
2012	2.01	2.30
2013	2.05	2.34
2014	2.09	2.39
2015	2.13	2.44
2016	2.18	2.49

Premises

- Based on \$15/BBL crude with high sulfur at 65% and low sulfur at 78% and freight at \$1.00/BBL.
- Overall inflation at 2%/yr does not impact oil prices or freight due to a chronic surplus of supply and ongoing technological improvements until 2005, thereafter prices rise at about 2%/yr.
- 6.3 million BTU/BBL.

FUELS SUPPLY DEPARTMENT

FCP 9402 - LOW SCENARIO

LIGHT FUEL OIL (#2)

.5% SULFUR DELIVERED TO TAMPA BAY TERMINAL

\$/MMBTU

1995 - 2005	3.25
2006	3.32
2007	3.38
2008	3.45
2009	3.52
2010	3.59
2011	3.66
2012	3.73
2013	3.81
2014	3.88
2015	3.96
2016	4.04

Premises

- See Residual Fuel Oil Premises.
- 5.8 million BTU/BBL.

FUELS SUPPLY DEPARTMENT
FCP 9402 - LOW SCENARIO
ORIMULSION
\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
1999	1.65	.41	2.06
2000	1.68	.42	2.10
2001	1.71	.43	2.14
2002	1.74	.43	2.17
2003	1.77	.44	2.21
2004	1.80	.45	2.25
2005	1.83	.45	2.28

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005 escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005 escalate 80% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.

**FUELS SUPPLY DEPARTMENT
FCP 9402 - HIGH SCENARIO
NATURAL GAS
DELIVERED ANCLOTE/POLK COUNTY
\$/MMBTU**

	HENRY HUB	SUNSHINE			FGT (Phase III)		
	N. Gas	Variable Transport	Fixed Demand	Total*	Variable Transport	Fixed Demand	Total*
1998	2.50	.10	.75	3.35	.15	.75	3.40
1999	2.60	.10	.80	3.50	.15	.80	3.55
2000	2.70	.10	.80	3.60	.15	.80	3.65
2001	2.80	.10	.80	3.70	.15	.80	3.75
2002	3.00	.10	.85	3.95	.15	.80	3.95
2003	3.10	.15	.85	4.10	.20	.80	4.10
2004	3.20	.15	.85	4.20	.20	.80	4.20
2005	3.40	.15	.85	4.40	.20	.80	4.40
2006	3.50	.15	.90	4.55	.20	.85	4.55
2007	3.65	.15	.90	4.70	.20	.85	4.70
2008	3.80	.15	.90	4.85	.20	.85	4.85
2009	3.95	.15	.90	5.00	.20	.85	5.00
2010	4.10	.15	.90	5.15	.20	.85	5.15
2011	4.30	.15	.90	5.35	.20	.85	5.35
2012	4.45	.15	.90	5.50	.20	.90	5.55
2013	4.60	.15	.90	5.65	.20	.90	5.70
2014	4.80	.15	.90	5.85	.20	.90	5.90
2015	5.00	.15	.90	6.05	.20	.90	6.10
2016	5.20	.15	.90	6.25	.20	.90	6.30

Premises

- Assumed natural gas will not track inflation post 2005.
(Gas will increase at about 4% per year vs. 5% per year inflation).
- Transport forecast for Sunshine assumes 50% of gas sourced through Koch Gateway and 50% from Mobile Bay.
- Total cost assumes 100% load factor.
- 1,000 BTU/CF.
- Variable transport includes compressor fuel cost.

* Assume 100% load factor

FUELS SUPPLY DEPARTMENT
FCP 9402 - HIGH SCENARIO
NATURAL GAS
DELIVERED UNIVERSITY OF FLORIDA
\$/MMBTU

FGT - FTS-1 + GRU

	HENRY HUB N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
1995	2.20	.30	.45	2.95
1996	2.30	.30	.45	3.05
1997	2.40	.30	.50	3.20
1998	2.50	.30	.50	3.30
1999	2.60	.30	.50	3.40
2000	2.70	.30	.50	3.50
2001	2.80	.30	.50	3.60
2002	3.00	.30	.55	3.85
2003	3.10	.30	.55	3.95
2004	3.20	.30	.55	4.05
2005	3.40	.30	.55	4.25
2006	3.50	.30	.60	4.40
2007	3.65	.30	.60	4.55
2008	3.80	.30	.60	4.70
2009	3.95	.30	.60	4.85
2010	4.10	.30	.60	5.00
2011	4.30	.30	.65	5.25
2012	4.45	.30	.65	5.40
2013	4.60	.35	.65	5.60
2014	4.80	.35	.65	5.80
2015	5.00	.35	.65	6.00
2016	5.20	.35	.70	6.25

* Assumes 100% load factor.

FUELS SUPPLY DEPARTMENT
FCP 9402 - HIGH SCENARIO
NATURAL GAS
DELIVERED SUWANNEE PLANT
\$/MMBTU

	HENRY HUB N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
1995	2.20	.15		
1996	2.30	.15	.75	3.10
1997	2.40	.15	.80	3.25
1998	2.50	.15	.80	3.35
1999	2.60	.15	.80	3.45
2000	2.70	.15	.80	3.55
2001	2.80	.15	.80	3.65
2002	3.00	.15	.80	3.75
2003	3.10	.15	.80	3.95
2004	3.20	.20	.80	4.05
2005	3.40	.20	.80	4.20
2006	3.50	.20	.85	4.45
2007	3.65	.20	.85	4.55
2008	3.80	.20	.85	4.70
2009	3.95	.20	.85	4.85
2010	4.10	.20	.85	5.00
2011	4.30	.20	.90	5.20
2012	4.45	.20	.90	5.40
2013	4.60	.20	.90	5.55
2014	4.80	.20	.90	5.70
2015	5.00	.20	.90	5.90
2016	5.20	.20	.95	6.15
			.95	6.35

* Assumes 100% load factor

FUELS SUPPLY DEPARTMENT
FCP 9402 - HIGH SCENARIO
RESIDUAL FUEL OIL
DELIVERED BARTOW/ANCLOTE
\$/MMBTU

	2.5%	1.0%
1995	2.50	2.70
1996	2.60	2.81
1997	2.70	2.92
1998	2.81	3.04
1999	2.92	3.16
2000	3.04	3.29
2001	3.16	3.42
2002	3.29	3.56
2003	3.42	3.70
2004	3.56	3.85
2005	3.70	4.00
2006	3.85	4.16
2007	4.00	4.33
2008	4.16	4.50
2009	4.33	4.68
2010	4.50	4.87
2011	4.68	5.06
2012	4.87	5.26
2013	5.06	5.47
2014	5.26	5.69
2015	5.47	5.92
2019	5.69	6.15

Premises

- ▣ Crude averages \$17/BBL in 1995 with high sulfur at 85% of crude and low sulfur at 95% of crude and \$1.00/BBL freight.
- ▣ Average prices rise at about 4%/yr (80% of high inflation rate of 5%/yr).
- ▣ 6.3 million BTU/BBL.

FUELS SUPPLY DEPARTMENT
 FCP 9402 - HIGH SCENARIO
 LIGHT FUEL OIL (#2)
 .5% SULFUR DELIVERED TO TAMPA BAY TERMINAL
 \$/MMBTU

1995	4.34
1996	4.56
1997	4.74
1998	4.93
1999	5.13
2000	5.33
2001	5.55
2002	5.77
2003	6.00
2004	6.24
2005	6.49
2006	6.75
2007	7.02
2008	7.30
2009	7.59
2010	7.90
2011	8.21
2012	8.54
2013	8.88
2014	9.23
2015	9.60
2016	9.99

Premises

- ▣ See Residual Fuel Oil Premises.
- ▣ 5.8 million BTU/BBL.

FUELS SUPPLY DEPARTMENT
FCP 9402 - HIGH SCENARIO
ORIMULSION
\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
			2.26
1999	1.65	.61	2.32
2000	1.70	.62	2.37
2001	1.74	.63	2.41
2002	1.78	.63	2.46
2003	1.82	.64	2.51
2004	1.86	.65	2.55
2005	1.90	.65	

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.
After 2005, escalate at 67% of inflation.

³ Fixed cost at 80% CF.
After 2005, escalate at 100% of inflation.

⁴ Sum of Orimulsion plus Scrubber Charge.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuels Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

SUBJECT: Fuel Cost Projection - Coal

TO: Mr. R. D. Niekum
Mr. K. H. Wieland

DATE: October 20, 1994

Please find attached a letter from Mr. Dennis Edwards of EFC updating their forecast of coal prices. Please consider this a revision to FCP 9402.

Dale Williams

Attachment:

cc: L. D. Brousseau
N. L. Davis
R. D. Dolan
D. G. Edwards
M. B. Foley
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
M. D. Rib
P. E. Toomey
J. R. Rocha
File
Forecast Book

ELECTRIC FUELS CORPORATION

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33711 (813) 824-6600

October 17, 1994

Mr. Dale D. Williams
Fuel and Special Projects
Florida Power Corporation - H2A
3201 - 34 Street, South
St. Petersburg, Florida 33711

Dear Mr. Williams:

This letter is written in response to your recent request for updated coal-price forecasts for the Crystal River 1 & 2 and 4 & 5 quality coals, for the period 1995 through 2005. The attached schedule (Attachment A) lists our forecast of delivered coal costs for this period. Based on information from our consultants, we are recommending that prices beyond 2005 should be trended with inflation times a .67 multiplier to reflect the forecast of these consultants that coal prices will not escalate as fast as general inflation. Also attached are our forecasts for incremental coal prices for the same period (Attachment B).

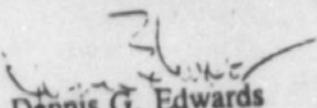
Please note that the overall price forecasts for the Crystal River units contained herein are in line with, or slightly lower than, the forecasts previously supplied to you. The reason for this continues to be that the anticipated price increases for low-sulfur coals due to environmental legislation has not yet materialized, and is currently expected to have only a moderate price impact on low-sulfur coals in the foreseeable future. This assumption affects our forecasts for spot prices, contract reopener prices, as well as new contract prices.

Regarding your request for price forecasts for coals supplied to the Polk County site, we have developed Attachment C. This Attachment presents 4 lb SO₂ Illinois Basin coal. Please note that the prices for "high-sulfur" coal is projected to increase at a much slower rate than our lower sulfur coals forecast because of forecasted reduced demand for this quality coal in the future. We used information from the *Hill and Associates May 1994* forecast to assist in this projection.

Mr. Dale D. Williams
October 17, 1994
Page 2

The "high" and "low" case projections that you requested are being prepared, and will be forwarded to you in the near future. If you have any questions, or require additional information on this matter, please let me know.

Sincerely,



Dennis G. Edwards
Vice President
Coal Procurement

DGE/ro

Attachments

cc: W. D. Carter
G. K. Orchard
D. M. Davis
R. A. Hemmer

ELECTRIC FUELS CORPORATION

Estimated Coal Prices

1995-2005

Crystal River 1 & 2

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	1,600	12,396	\$45.84	\$1.85
1996: January-December	1,750	12,500	\$43.86	\$1.75
1997: January-December	1,750	12,500	\$44.90	\$1.80
1998: January-December	1,750	12,500	\$45.94	\$1.84
1999: January-December	1,700	12,500	\$47.19	\$1.89
2000: January-December	1,700	12,500	\$48.26	\$1.93
2001: January-December	1,700	12,500	\$49.51	\$1.98
2002: January-December	1,700	12,500	\$50.50	\$2.02
2003: January-December	1,700	12,500	\$51.50	\$2.06
2004: January-December	1,700	12,500	\$52.50	\$2.10
2005: January-December	1,700	12,500	\$53.50	\$2.14

Crystal River 4 & 5

Year	Tons (000s)	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	3,500	12,620	\$49.51	\$1.96
1996: January-December	3,500	12,616	\$51.73	\$2.05
1997: January-December	3,500	12,616	\$52.75	\$2.09
1998: January-December	3,500	12,616	\$53.57	\$2.12
1999: January-December	3,500	12,623	\$54.70	\$2.17
2000: January-December	3,500	12,623	\$56.30	\$2.23
2001: January-December	3,500	12,623	\$57.56	\$2.28
2002: January-December	3,500	12,623	\$58.82	\$2.33
2003: January-December	3,500	12,623	\$59.83	\$2.37
2004: January-December	3,500	12,623	\$60.84	\$2.41
2005: January-December	3,500	12,623	\$61.85	\$2.45

Crystal River 1 & 2 and 4 & 5

Year	Btu/lb	\$/Ton	Average \$/MBtu
1995: January-December	12,550	\$48.35	\$1.93
1996: January-December	12,578	\$49.10	\$1.95
1997: January-December	12,578	\$50.14	\$1.99
1998: January-December	12,578	\$51.02	\$2.03
1999: January-December	12,583	\$52.24	\$2.08
2000: January-December	12,583	\$53.60	\$2.13
2001: January-December	12,583	\$54.91	\$2.18
2002: January-December	12,583	\$56.42	\$2.24
2003: January-December	12,583	\$57.09	\$2.27
2004: January-December	12,583	\$58.10	\$2.31
2005: January-December	12,583	\$59.11	\$2.35

ELECTRIC FUELS CORPORATION
 Estimated Incremental Coal Prices
 1995—2005

Crystal River 1 & 2

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$41.45	\$1.66
1996: January—December	12,500	\$42.36	\$1.70
1997: January—December	12,500	\$43.23	\$1.73
1998: January—December	12,500	\$44.11	\$1.76
1999: January—December	12,500	\$45.14	\$1.81
2000: January—December	12,500	\$46.25	\$1.85
2001: January—December	12,500	\$47.50	\$1.90
2002: January—December	12,500	\$48.50	\$1.94
2003: January—December	12,500	\$49.75	\$1.99
2004: January—December	12,500	\$50.75	\$2.03
2005: January—December	12,500	\$52.00	\$2.08

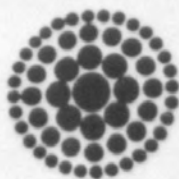
Crystal River 4 & 5

<i>Year</i>	<i>Btu/lb</i>	<i>\$/Ton</i>	<i>Average \$/MBtu</i>
1995: January—December	12,500	\$43.30	\$1.73
1996: January—December	12,500	\$43.99	\$1.76
1997: January—December	12,500	\$45.35	\$1.81
1998: January—December	12,500	\$46.75	\$1.87
1999: January—December	12,500	\$48.29	\$1.93
2000: January—December	12,500	\$50.00	\$2.00
2001: January—December	12,500	\$51.50	\$2.06
2002: January—December	12,500	\$53.00	\$2.12
2003: January—December	12,500	\$54.50	\$2.18
2004: January—December	12,500	\$56.00	\$2.24
2005: January—December	12,500	\$57.50	\$2.30

ELECTRIC FUELS CORPORATION
 Estimated Delivered Coal Prices — 1998—2016 Forecast
 Polk County Site

Year	Tons (000's)	Illinois Basis > 4 Lb SO ₂		
		Btu/Lb	\$/Ton	\$/MBtu
1998: January—December	2,136	11,700	\$42.12	\$1.80
1999: January—December	2,136	11,700	\$42.59	\$1.82
2000: January—December	2,136	11,700	\$43.06	\$1.84
2001: January—December	2,136	11,700	\$43.52	\$1.86
2002: January—December	2,136	11,700	\$42.23	\$1.89
2003: January—December	2,136	11,700	\$44.93	\$1.92
2004: January—December	2,136	11,700	\$45.63	\$1.95
2005: January—December	2,136	11,700	\$46.33	\$1.98
2006: January—December	2,136	11,700	\$47.03	\$2.01
2007: January—December	2,136	11,700	\$47.50	\$2.03
2008: January—December	2,136	11,700	\$47.97	\$2.05
2009: January—December	2,136	11,700	\$48.91	\$2.09
2010: January—December	2,136	11,700	\$49.84	\$2.13
2011: January—December	2,136	11,700	\$50.78	\$2.17
2012: January—December	2,136	11,700	\$51.71	\$2.21
2013: January—December	2,136	11,700	\$52.42	\$2.24
2014: January—December	2,136	11,700	\$53.12	\$2.27
2015: January—December	2,136	11,700	\$53.82	\$2.30
2016: January—December	2,136	11,700	\$54.52	\$2.33

Note: The coal prices used in the above forecast were taken from *The Outlook for US Steam Coal Demand, Supply and Prices 1994 - 2016*, by Hill & Associates, dated May 1994. Transportation cost estimates are based on current cents ton/mile figures used in conjunction with the Polk County site escalated by an assumed contract escalation package which results in an average 2.0 percent increase per year.



**Florida
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INTEROFFICE CORRESPONDENCE

Fuel Supply Department
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231-4537
TELEPHONE

SUBJECT: **Fuel Cost Projection (Supplement)**

TO: **Mr. R. D. Niekum**
Mr. K. H. Wieland

DATE: **September 20, 1994**

Please find attached a supplement to Fuel Cost Projection FCP 9402 which was distributed on September 8, 1994. This supplement projects prices and available volumes of interruptible gas transportation on the Florida Gas Transmission Pipeline.

If you have any questions or require additional information, please advise.

T. Dan Putnam
T. Dan Putnam

Attachment:

cc: L. D. Brousseau
D. M. Davis
N. L. Davis
D. L. Dawson
R. D. Dolan
M. B. Foley
J. G. Keppeler
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
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J. J. Murphy
D. M. OShea
M. D. Rib
J. R. Rocha
J. R. Stitt
P. E. Toomey
D. D. Williams
File
Forecast Book

FUELS SUPPLY DEPARTMENT
FPC 9402
NATURAL GAS (INTERRUPTIBLE TRANSPORTATION)
DELIVERED TO INTERCESSION CITY
\$/MMBTU

	HENRY HUB N. GAS	COMP. FUEL	FGT VAR. TRANSP.	KUA VAR. TRANSP.	TOTAL DELVD COST
				0.05	2.89
		0.05	0.66	0.05	2.96
1995	2.13	0.05	0.66	0.05	3.07
1996	2.20	0.05	0.67	0.06	3.24
1997	2.30	0.06	0.67	0.06	3.35
1998	2.45	0.06	0.68	0.06	3.45
1999	2.55	0.06	0.68	0.06	3.56
2000	2.65	0.06	0.69	0.06	3.71
2001	2.75	0.06	0.69	0.07	3.89
2002	2.90	0.07	0.70	0.07	4.04
2003	3.05	0.07	0.70	0.07	4.26
2004	3.20	0.08	0.71	0.07	4.36
2005	3.40	0.08	0.71	0.08	4.48
2006	3.50	0.08	0.72	0.08	4.60
2007	3.60	0.08	0.72	0.08	4.72
2008	3.72	0.09	0.73	0.08	4.84
2009	3.82	0.09	0.73	0.09	4.98
2010	3.94	0.09	0.74	0.09	5.10
2011	4.06	0.09	0.74	0.09	5.25
2012	4.18	0.10	0.75	0.10	5.39
2013	4.31	0.10	0.75	0.10	5.53
2014	4.44	0.10	0.76	0.10	5.68
2015	4.57	0.11	0.76		
2016	4.71				

FUELS SUPPLY DEPARTMENT
FCP 9402
NATURAL GAS (INTERRUPTIBLE TRANSPORTATION)
DELIVERED TO AVON PARK, HIGGINS, BARTOW & CRYSTAL RIVER
\$/MMBTU

	HENRY HUB N. GAS	COMP. FUEL	FGT	VAR. TRANSP.	TOTAL DELV'D COST
				0.66	2.84
1995	2.13	0.05		0.66	2.91
1996	2.20	0.05		0.67	3.02
1997	2.30	0.05		0.67	3.18
1998	2.45	0.06		0.68	3.29
1999	2.55	0.06		0.68	3.39
2000	2.65	0.06		0.69	3.50
2001	2.75	0.06		0.69	3.65
2002	2.90	0.06		0.70	3.82
2003	3.05	0.07		0.70	3.97
2004	3.20	0.07		0.71	4.19
2005	3.40	0.08		0.71	4.29
2006	3.50	0.08		0.72	4.40
2007	3.60	0.08		0.72	4.52
2008	3.72	0.08		0.73	4.64
2009	3.82	0.09		0.73	4.76
2010	3.94	0.09		0.74	4.89
2011	4.06	0.09		0.74	5.01
2012	4.18	0.09		0.75	5.16
2013	4.31	0.10		0.75	5.29
2014	4.44	0.10		0.76	5.43
2015	4.57	0.10		0.76	5.58
2016	4.71	0.11			

FUELS SUPPLY DEPARTMENT
FCP 9402
INTERRUPTIBLE GAS TRANSPORTATION ON FGT
1995 - 2000
MMBTU'S/HR.

January	5,750
February	5,750
March	5,750
April	5,000
May	2,900
June	2,750
July	2,475
August	2,475
September	2,475
October	5,000
November	5,750
December	5,750

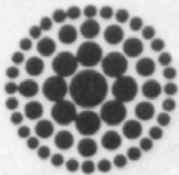
Note: • After the year 2000 reduce the above Interruptible gas quantities shown above by 50%.

- Max flow rate restrictions on FGT

Avon Park C.T.	450 MMBtu's/hr.
Bartow Steam	1,700 MMBtu's/hr.
Crystal River	4,100 MMBtu's/hr.
Higgins C.T.	2,150 MMBtu's/hr. (May - Sept.)
	1,900 MMBtu's/hr. (Oct. - Apr.)
Intercession City	6,000 MMBtu's/hr.

Premises for Interruptible Gas:

- Compressor fuel requirements on FGT remain at 2.25%.
- FGT requests rate case to increase current I.T. rate between FTS-1 and FTS-2 rates.
- KUA transportation is assumed to increase at 3.5%/yr. which is the same general inflation rate used throughout FCP 9402. Final contract may provide different pricing scenarios.
- FGT transportation increases \$0.005/MMBtu annually.



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SUBJECT: Fuel Cost Projection

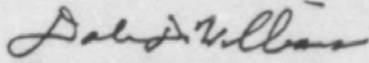
TO: Mr. R. D. Niekum
Mr. K. H. Wieland

DATE: September 8, 1994

Please find attached Fuel Cost Projection 9402. This represents an updated long range base case forecast.

In light of all of the efforts that have been spent to date in support of our generation planning studies, we have provided these forecasts. In order to maintain consistency in all of our planning efforts, please use these numbers until notified otherwise.

If you have any questions or require additional information, please advise.


Dale D. Williams

Attachments:

cc: L. D. Brousseau
D. M. Davis
N. L. Davis
R. D. Dolan
M. B. Foley
J. G. Keppeler
R. W. Lehnhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
D. M. OShea
M. D. Rib
J. R. Rocha
File
Forecast Book

copy sent to Peter Toomey 9/9

FUELS SUPPLY DEPARTMENT
FCP 9402
ORIMULSION
\$/MMBTU¹

	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
		.410	2.060
1999	1.650	.420	2.120
2000	1.700	.430	2.180
2001	1.750	.430	2.222
2002	1.792	.440	2.283
2003	1.843	.450	2.344
2004	1.894	.450	2.234
2005	1.784	.460	2.294
2006	1.334	.470	2.356
2007	1.886	.480	2.419
2008	1.939	.480	2.473
2009	1.993	.490	2.533
2010	2.043	.500	2.600
2011	2.100	.510	2.669
2012	2.159	.510	2.729
2013	2.219	.520	2.795
2014	2.275	.530	2.868
2015	2.338	.540	2.944
2016	2.404		

¹ 4.5 million BTU/lb.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors.

³ Fixed cost at 80% CF.

⁴ Sum of Orimulsion plus Scrubber Charge.

**FUELS SUPPLY DEPARTMENT
FCP 9402
NATURAL GAS
DELIVERED ANCLOTE/POLK COUNTY
\$/MMBTU**

		HENRY HUB	SUNSHINE			FGT (Phase III)		
		N. Gas	Variable Transport	Fixed Demand	Total*	Variable Transport	Fixed Demand	Total*
PIRA	1998	2.45	.09	.71	3.25	.14	.75	3.34
"	1999	2.55	.09	.74	3.38	.15	.76	3.46
"	2000	2.65	.09	.76	3.50	.15	.76	3.56
"	2001	2.75	.09	.79	3.63	.15	.77	3.67
"	2002	2.80	.10	.81	3.81	.15	.78	3.83
"	2003	3.05	.11	.82	3.98	.16	.79	4.00
"	2004	3.20	.11	.84	4.15	.16	.79	4.15
"	2005	3.40	.11	.85	4.36	.16	.80	4.36
Gas at 3.0% yr**	2006	3.50	.11	.87	4.48	.16	.81	4.47
"	2007	3.60	.12	.88	4.60	.17	.82	4.57
"	2008	3.72	.12	.90	4.74	.17	.83	4.72
"	2009	3.82	.12	.90	4.84	.17	.83	4.82
"	2010	3.94	.13	.90	4.97	.17	.84	4.95
"	2011	4.06	.13	.90	5.09	.18	.85	5.09
"	2012	4.18	.13	.90	5.21	.18	.86	5.22
"	2013	4.31	.14	.90	5.35	.18	.87	5.36
"	2014	4.44	.14	.90	5.48	.18	.88	5.50
"	2015	4.57	.14	.90	5.61	.19	.88	5.64
"	2016	4.71	.14	.90	5.75	.19	.89	5.79

Premises

- 1998 - 2005 PIRA forecast used (see attached).
- Assumed Natural Gas will not track inflation post 2005.
(gas will increase at 3% per year vs. 3.5% per year inflation)
- Transport forecast for Sunshine assumes 50% of gas sourced through Koch Gateway and 50% from Mobile Bay.
- Total cost assumes 100% load factor.
- 1,000 BTU/CF
- Variable transport includes compressor fuel cost.

* Assume 100% load factor

** 85% of 3.5%

FUELS SUPPLY DEPARTMENT
FCP 9402
NATURAL GAS
DELIVERED UNIVERSITY OF FLORIDA
\$/MMBTU

FGT - FTS-1 + GRU

	HENRY HUB N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
		.26	.43	2.79
1994	2.10			
		.26	.44	2.83
1995	2.13			
		.26	.45	2.90
1996	2.20			
		.27	.46	3.03
1997	2.30			
		.27	.47	3.19
1998	2.45			
		.27	.48	3.30
1999	2.55			
		.27	.49	3.41
2000	2.65			
		.28	.50	3.53
2001	2.75			
		.28	.51	3.69
2002	2.90			
		.28	.52	3.85
2003	3.05			
		.28	.53	4.01
2004	3.20			
		.29	.54	4.23
2005	3.40			
		.29	.56	4.33
2006	3.50			
		.29	.57	4.46
2007	3.60			
		.29	.58	4.59
2008	3.72			
		.30	.59	4.71
2009	3.82			
		.30	.60	4.84
2010	3.94			
		.30	.61	4.97
2011	4.06			
		.30	.62	5.10
2012	4.18			
		.31	.63	5.25
2013	4.31			
		.31	.64	5.39
2014	4.44			
		.31	.65	5.53
2015	4.57			
		.32	.66	5.69
2016	4.71			

* Assumes 100% load factor.

COMPANY CONFIDENTIAL

FUELS SUPPLY DEPARTMENT
FCP 9402
NATURAL GAS
DELIVERED SUWANNEE PLANT
\$/MMBTU

	HENRY HUB N. GAS	VARIABLE TRANSPORT	FIXED DEMAND	TOTAL*
			.75	2.98
1994	2.10	.13	.75	3.01
1995	2.13	.13	.76	3.09
1996	2.20	.13	.76	3.20
1997	2.30	.14	.77	3.36
1998	2.45	.14	.77	3.46
1999	2.55	.14	.78	3.58
2000	2.65	.15	.78	3.68
2001	2.75	.15	.79	3.84
2002	2.90	.15	.79	3.99
2003	3.05	.15	.80	4.16
2004	3.20	.16	.81	4.37
2005	3.40	.16	.82	4.48
2006	3.50	.16	.83	4.59
2007	3.60	.16	.84	4.73
2008	3.72	.17	.85	4.85
2009	3.82	.17	.86	4.97
2010	3.94	.17	.87	5.10
2011	4.06	.17	.88	5.24
2012	4.18	.18	.89	5.38
2013	4.31	.18	.90	5.52
2014	4.44	.18	.91	5.67
2015	4.57	.19	.92	5.82
2016	4.71	.19		

* Assumes 100% load factor

**FUELS SUPPLY DEPARTMENT
FCP 9402
LIGHT FUEL OIL (#2)
.5% SULFUR DELIVERED TO TAMPA BAY TERMINAL
\$/MMBTU**

1994	4.18
1995	4.18
1996	4.56
1997	4.72
1998	4.87
1999	5.03
2000	5.27
2001	5.43
2002	5.59
2003	5.83
2004	6.00
2005	6.31
2006	6.53
2007	6.76
2008	7.00
2009	7.24
2010	7.49
2011	7.76
2012	8.02
2013	8.31
2014	8.60
2015	8.90
2016	9.21

Premises

- 1994 - 2005 PIRA long range forecast plus freight and taxes to Bartow plant via barge (8¢/gallon in 1994). Freight and taxes assumed to escalate with inflation at 3.5%/yr.
- Post 2005 - Total price will escalate with inflation at 3.5%/yr.
- 5.8 million BTU/BBL.

**FUELS SUPPLY DEPARTMENT
FCP 9402
OIL TRANSPORTATION COST
\$/MMBTU**

1994¹Residual Fuel Oil

Suwannee	.77
----------	-----

Light Fuel Oil

Avon Park	.19
Bartow/Bayboro	.19
Debary	.24
Higgins	.09
Intercession City ²	.09
Port St. Joe	.52
Rio Pinar	.22
Suwannee	.23
Turner	.23
Polk County ³	.46
Crystal River	.19

¹ Escalate with inflation at 3.5%/yr.

² Add \$24,000/month for dedicated storage in Tampa

³ Includes premium for low sulfur

FUELS SUPPLY DEPARTMENT
FCP 9402
COAL
\$/MMBTU

	CR 1 & 2 AVG.	INCREMENTAL	CR 1 & 2 AVG.	INCREMENTAL	H.S. COAL
	1995 1.87	1.66	1.98	1.73	
	1996 1.80	1.70	2.09	1.77	
	1997 1.84	1.76	2.14	1.83	
	1998 1.87	1.82	2.21	1.89	
3.5% X .80	1999 1.92	1.87	2.27	2.00	1.76
"	2000 1.98	1.93	2.34	2.05	1.81
"	2001 2.03	2.00	2.40	2.10	1.86
"	2002 2.09	2.04	2.46	2.15	1.91
"	2003 2.15	2.10	2.53	2.20	1.97
"	2004 2.21	2.16	2.60	2.30	2.02
"	2005 2.27	2.22	2.45	2.35	2.03
"	2006 2.33	2.28	2.52	2.42	2.14
"	2007 2.40	2.35	2.59	2.49	2.20
"	2008 2.46	2.41	2.66	2.56	2.26
"	2009 2.53	2.48	2.74	2.64	2.32
"	2010 2.60	2.55	2.81	2.71	2.38
"	2011 2.68	2.63	2.89	2.79	2.45
"	2012 2.75	2.70	2.97	2.87	2.52
"	2013 2.83	2.78	3.06	2.96	2.59
"	2014 2.91	2.86	3.14	3.04	2.66
"	2015 2.99	2.94	3.23	3.13	2.74
"	2016 3.07	3.02	3.32	3.22	2.81
					2.89

Premises

- Derived from EFC numbers (current Fuel Adjustment Forecast 9401 and Long Term from 9302).
- 1999 - 2016 Avg. Coal will escalate at 80% of inflation.
- 2005: Assumed a reduction in CR 4 & 5 prices due to contract reformation.
- CR 1 & 2 Coal at 12,500 BTU/lb.
- CR 4 & 5 Coal at 12,700 BTU/lb.

FUELS SUPPLY DEPARTMENT
FCP 9402
PETROLEUM COKE
\$/MMBTU

		CRYSTAL RIVER	INLAND FREIGHT	POLK COUNTY
ESC - Oil	1994	1.00	.20	1.20
"	1995	1.04	.20	1.24
"	1996	1.08	.20	1.28
"	1997	1.13	.20	1.33
"	1998	1.18	.21	1.39
"	1999	1.23	.22	1.45
"	2000	1.27	.23	1.50
"	2001	1.31	.24	1.55
"	2002	1.38	.25	1.63
"	2003	1.45	.26	1.71
"	2004	1.49	.27	1.76
"	2005	1.55	.28	1.83
ESC - 3.5%	2006	1.60	.29	1.89
"	2007	1.66	.30	1.96
"	2008	1.71	.31	2.02
"	2009	1.78	.32	2.10
"	2010	1.84	.33	2.17
"	2011	1.91	.34	2.25
"	2012	1.97	.35	2.32
"	2013	2.04	.36	2.40
"	2014	2.11	.36	2.47
"	2015	2.19	.38	2.57
"	2016	2.26	.39	2.65

Premises

- Current market from various suppliers for 1994 plus EFC freight to Crystal River. Inland Freight based on estimated truck freight.
- Escalation tracks oil from 1995 - 2005.
- + Inflation thereafter.
- 14,000 BTU/lb.

**FUELS SUPPLY DEPARTMENT
FCP 9402
RESIDUAL FUEL OIL
DELIVERED BARTOW/ANCLOTE
\$/MMBTU**

↓

		2.5%	1.0%
1994	FPC	2.14	2.54
1995	"	2.22	2.65
1996	PIRA	2.30	2.72
1997	"	2.40	2.84
1998	"	2.51	2.99
1999	"	2.62	3.12
2000	"	2.71	3.23
2001	"	2.79	3.34
2002	"	2.94	3.46
2003	"	3.08	3.58
2004	"	3.17	3.70
2005	"	3.29	3.83
2006	plus 3.0%/yr*	3.39	3.94
2007	"	3.49	4.06
2008	"	3.60	4.19
2009	"	3.70	4.31
2010	"	3.81	4.44
2011	"	3.93	4.57
2012	"	4.04	4.71
2013	"	4.17	4.85
2014	"	4.29	5.00
2015	"	4.42	5.15
2016	"	4.55	5.30

Premises

- 1994 & 1995 numbers are consistent with the Fuel Adjustment Forecast (9401).
- 1996 - 2005 PIRA long range forecast and freight (see attached).
- Assumed oil will not track inflation post 2005. PIRA premises are available. This forecast does not support nor deny its accuracy.
- 6.3 million BTU/BBL.

FUELS SUPPLY DEPARTMENT
FCP 9402
NUCLEAR FUEL EXPENSE PROJECTIONS

¢/MMBTU's

38

- Does not include spent fuel disposal charges or enrichment plant decommissioning charges¹.
- Escalate future cycles with inflation.

¹ Provided by Nuclear Operations



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Fuels Supply Department
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231-4532
TELEPHONE

SUBJECT: **Fuel Cost Projection**

TO: **Mr. R. D. Niekum**
Mr. K. H. Wieland

DATE: **September 19, 1994-**

Please find attached a revised Fuel Cost Projection 9402. The revision is based on updated coal prices from EFC which also changes the Orimulsion prices since they are expected to escalate with coal cost.

If you have any questions or require additional information, please advise.

Dale D. Williams

Attachments:

cc: L. D. Brousseau
D. M. Davis
N. L. Davis
R. D. Dolan
M. B. Foley
W. Hungerford
J. G. Keppeler
R. W. Lehrhoff
J. R. Lindquist
G. E. Matzke
W. C. Micklon
D. M. OShea
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FUELS SUPPLY DEPARTMENT
FCP 9402 (Revised 9/16/94)
COAL
\$/MMBTU

	CR 1 & 2 AVG.	INCREMENTAL	CR 4 & 5 AVG.	INCREMENTAL	H.S. COAL-POLK
	1995 1.84	1.66	1.98	1.73	
	1996 1.75	1.69	2.07	1.76	
	1997 1.79	1.73	2.12	1.81	
	1998 1.82	1.76	2.13	1.87	
	1999 1.87	1.80	2.18	1.93	1.80
	2000 1.93	1.85	2.24	2.00	1.82
	2001 1.98	1.89	2.29	2.06	1.84
	2002 2.03	1.94	2.33	2.12	1.86
3.5% X .67	2003 2.08	1.98	2.38	2.17	1.89
"	2004 2.12	2.03	2.44	2.22	1.92
"	2005 2.17	2.08	2.34	2.26	1.95
"	2006 2.22	2.12	2.39	2.32	1.98
"	2007 2.27	2.17	2.45	2.38	2.01
"	2008 2.33	2.22	2.51	2.43	2.03
"	2009 2.38	2.27	2.56	2.49	2.05
"	2010 2.44	2.33	2.62	2.54	2.09
"	2011 2.49	2.38	2.68	2.60	2.13
"	2012 2.55	2.44	2.74	2.66	2.17
"	2013 2.61	2.49	2.81	2.72	2.21
"	2014 2.67	2.55	2.87	2.79	2.24
"	2015 2.73	2.61	2.93	2.85	2.27
"	2016 2.79	2.67	3.01	2.91	2.30
					2.33

Premises

- Derived from EFC numbers
- 2002 - 2016 Avg. Coal will escalate at 67% of inflation $\approx$ 2.3%/yr.
- 2005: Assumed a reduction in CR 4 & 5 prices due to contract reformation.
- CR 1 & 2 Coal at 12,500 BTU/lb.
- CR 4 & 5 Coal at 12,700 BTU/lb. (after 1999 = 12,500 BTU/lb.)
- Polk County coal @ 11,700 BTU/lb.

FUELS SUPPLY DEPARTMENT
FCP 9402 (Revised 9/16/94)
ORIMULSION
\$/MMBTU¹

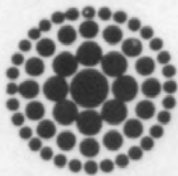
	<u>ORIMULSION²</u>	<u>SCRUBBER CHARGE³</u>	<u>TOTAL⁴</u>
1999	1.65		
2000	1.70	.41	
2001	1.73	.42	2.06
2002	1.76	.43	2.12
2003	1.80	.43	2.16
2004	1.85	.44	2.19
2005	1.77	.45	2.24
2006	1.81	.45	2.30
2007	1.85	.46	2.22
2008	1.90	.47	2.27
2009	1.94	.48	2.32
2010	1.99	.48	2.38
2011	2.04	.49	2.42
2012	2.08	.50	2.48
2013	2.13	.51	2.54
2014	2.18	.51	2.59
2015	2.23	.52	2.64
2016	2.28	.53	2.70
		.54	2.76
			2.82

¹ 4.5 million BTU/BBL.

² Escalates with CR 4 & 5 coal - ignores potential ceiling or floors - delivered prices to Bartow Terminal.

³ Fixed cost at 80% CF.

⁴ Sum of Orimulsion plus Scrubber Charge.



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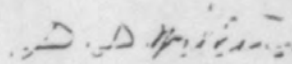
SUBJECT: **Fuel Cost Projections-FCP 9401**

TO: **Mr. Karl Wieland
Mr. Bob Niekum**

DATE: **May 31, 1994**

Please find attached the Fuel Cost Projection FCP 9401. This forecast is for the fuel adjustment projection period October 1994 through March 1995.

If you have any questions or require additional information, please advise.


D. D. Williams

DDW/jkv

Attachments:

cc: T. L. Brier
L. D. Brousseau
D. M. Davis (EFC)
N. L. Davis
R. D. Dolan
M. B. Foley
J. A. Hancock
J. G. Keppeler
R. W. Lehnhoff
J. P. Lindquist
G. E. Matzke
W. C. Micklon
D. M. OShea
L. C. Zyki
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Forecast Book

ELECTRIC FUELS CORPORATION

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33711 (813) 824-6600

May 27, 1994

Mr. Dale D. Williams
Principal Fuel Buyer
FLORIDA POWER CORPORATION
P. O. Box 14042
St. Petersburg, Florida 33733

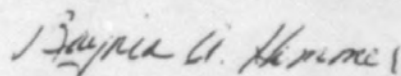
Dear Dale:

Attached are the June 1994 to March 1995 coal-price forecasts for Crystal River Units 1 & 2 (Attachment A), Crystal River Units 4 & 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your October 1994 - March 1995 fuel-adjustment filing. We have based our calculations on the latest financial estimates for 1994 and 1995 provided by our Accounting Department, and the assumptions listed on Appendix I.

If you require additional information, please call me or Donna Davis.

Sincerely,

ELECTRIC FUELS CORPORATION



Raynia A. Hemmer
Contract Administration Specialist

RAH:jss
Attachments

cc: W. D. Carter
D. J. Clark, Jr.
D. G. Edwards
D. M. Davis
G. K. Orchard

ELECTRIC FUELS CORPORATION
JUNE 1994 TO MARCH 1995 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu	Incremental c/MMBtu
<u>1994</u>					
June	154	12,267	47.57	193.91	164.52
July	154	12,267	47.67	194.32	164.88
August	164	12,261	47.38	193.22	164.88
September	164	12,261	47.37	193.17	164.88
October	164	12,261	47.68	194.42	165.24
November	110	12,143	45.17	185.98	165.24
December	164	12,261	47.69	194.49	165.24
<u>1995</u>					
January	182	12,320	45.98	186.60	167.72
February	132	12,373	46.15	186.50	167.20
March	132	12,373	46.12	186.38	167.20

ELECTRIC FUELS CORPORATION
JUNE 1994 TO MARCH 1995 COAL-PRICE FORECAST
CRYSTAL RIVER 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu	Incremental c/MMBtu
<u>1994</u>					
June	323	12,645	50.09	198.05	169.92
July	323	12,645	50.18	198.43	170.28
August	323	12,645	50.15	198.29	170.28
September	323	12,645	50.14	198.27	170.28
October	323	12,645	50.23	198.60	170.64
November	218	12,705	49.85	196.20	170.64
December	323	12,645	50.23	198.62	170.64
<u>1995</u>					
January	295	12,651	49.78	196.74	173.12
February	295	12,651	50.01	197.63	172.60
March	295	12,651	50.00	197.61	172.60

ELECTRIC FUELS CORPORATION
JUNE 1994 TO MARCH 1995 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2 and 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu
<u>1994</u>				
June	477	12,523	49.27	196.74
July	477	12,523	49.37	197.13
August	487	12,515	49.21	196.61
September	487	12,515	49.21	196.59
October	487	12,515	49.37	197.23
November	328	12,516	48.28	192.87
December	487	12,515	49.37	197.25
<u>1995</u>				
January	477	12,525	48.33	192.94
February	427	12,566	48.82	194.25
March	427	12,566	48.80	194.19



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1, 1994 - MARCH 31, 1995 Page 1 of 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE AS OF APRIL 1994, AND 1993 ANNUAL PERCENT CHANGES. THE FLORIDA PROGRESS CORPORATE ANNUAL PROFIT PLAN (THE PLAN) INFLATION ASSUMPTION OF 3.0% FOR 1994 AND 3.5% FOR 1995 (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- ONE CF 1 & 2 COAL CONTRACT OF 850,000 TONS EXPIRES DECEMBER 31, 1994, AND FORECASTED REPLACEMENT IS WITH A 500,000 TON COAL CONTRACT. TWO CR 4 & 5 CONTRACTS REFLECT MARKET REOPENER PRICES IN JANUARY 1995. NO MARKET REOPENERS ARE APPLICABLE IN 1994.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET-PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S (EFC'S COAL-INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL-MARKET INTELLIGENCE.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES. OUR ESTIMATE OF CSX CAPACITY FOR 1994 HAS BEEN REDUCED BY 200,000 TONS, REFLECTING YEAR-TO-DATE 1994 PERFORMANCE.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT THE PLAN INFLATION ASSUMPTION OF 3.0% FOR 1994 AND 3.5% FOR 1995 (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT TWO SETS OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF FEBRUARY 10, 1994, AND FEBRUARY 1, 1995, RESPECTIVELY, AT A COST PER SET OF APPROXIMATELY \$4.2 MILLION.
- 1995 WATER FREIGHT IS ESTIMATED AT THE CURRENT MARKET RATE ESCALATED AT FORECASTED ESCALATION OF THE INDIVIDUAL INDICES IN ACCORDANCE WITH ESCALATION PROVISIONS OF THE WATERBORNE COMPONENT.



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS OCTOBER 1, 1994 - MARCH 31, 1995 Page 2 of 2

GENERAL ADMINISTRATION

- G & A COSTS INCLUDE INTEREST ON \$16 MILLION IN MEDIUM-TERM NOTES, ISSUED FEBRUARY 1994, AND OTHER COSTS AT CURRENT LEVELS, EXCEPT FOR PROFESSIONAL FEES WHICH WERE LEFT AT THE 1994 ANNUAL PROFIT PLAN LEVEL.
- 37 PERCENT EFFECTIVE TAX RATE ASSUMED FOR INCOME-TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON LETTER FROM FPC DATED MAY 19, 1994, WHICH REFLECTED A TOTAL REQUIREMENT OF 5,600,000 TONS FOR 1994, AND 5,200,000 TONS FOR 1995.
- 1994 CONTRACT TONNAGE INCLUDES 379,000 TONS DEFERRED FROM 1993 TO 1994. FPC'S 200,000-TON BURN REDUCTION FROM THE LAST FUEL-ADJUSTMENT FORECAST WAS TAKEN FROM CR 1 & 2 SPOT RAIL TONS. ADDITIONALLY, OUR 1994 TONS DELIVERED PLAN WAS REDUCED BY 100,000 TONS (SPLIT EQUALLY BETWEEN WATER AND RAIL DELIVERIES) TO WORK TOWARDS ACHIEVING INVENTORY TARGETS. DUE TO THE SMALL BURN PROJECTION IN 1995, WE HAVE NOT ATTEMPTED ANY FURTHER INVENTORY REDUCTION FOR THAT YEAR.

EFC/RAH
5/27/94

FUELS SUPPLY DEPARTMENT

FCP 9401

RESIDUAL FUEL OIL PRICE PROJECTIONS

Delivered to Bartow Terminal

	2.5% SULFUR		1.0% SULFUR	
	<u>\$/BBL.</u>	<u>\$/MMBTU*</u>	<u>\$/BBL.</u>	<u>\$/MMBTU*</u>
1994				
Jun - Sept	13.50	2.14	15.00	2.38
Oct - Dec	13.50	2.14	17.00	2.70
1995				
Jan - Mar	13.00	2.06	16.00	2.54

* 6.3 MMBTU/BBL.

FUELS SUPPLY DEPARTMENT

FCP 9401

#2 FUEL OIL PRICE PROJECTION

Delivered out of Suppliers Terminal

	<u>¢/GALLON</u>	<u>\$/MMBTU*</u>
1994		
Jun - Sept	55	3.98
Oct - Dec	65	4.71
1995		
Jan - Mar	62	4.49

* 5.8 million BTU/BBL. & 42 gallons/BBL.

FUELS SUPPLY DEPARTMENT

FCP 9401

OIL TRANSPORT COST TO DELIVER TO PLANT LOCATIONS

6/94 - 3/95

<u>Location</u>	<u>Price/Unit</u>	<u>\$/MMBTU</u>
RESIDUAL FUEL OIL	\$/BBL.	
Suwannee	4.87	.77
#2 FUEL OIL	¢/Gallon	
Avon Park	2.6	.19
Bartow/Bayboro	1.6	.12
Debary	2.8	.20
Higgins	1.3	.09
Intercession City ⁽¹⁾	1.2	.09
Port St. Joe	7.2	.52
Rio Pinar	3.0	.22
Suwannee	3.2	.23
Turner	3.2	.23
Univ. of Florida ⁽²⁾	6.4	.46

⁽¹⁾ Additional \$24,000/month fixed charge for segregated storage in Tampa

⁽²⁾ Includes 4¢/gallon premium for Kerosine

FUELS SUPPLY DEPARTMENT

FCP 9401

NATURAL GAS

Delivered to University of Florida

Available Firm Volume: 9,300 MMBTU/day⁽¹⁾

	<u>N. Gas into FGT</u>	<u>Variable Transport Component⁽²⁾</u>	<u>Fixed Demand Charge</u>	<u>Total Del'd Price⁽³⁾</u>
1994				
Jun - Sept	2.15	.27	.43	2.85
Oct - Dec	2.35	.27	.43	3.05
1995				
Jan - Mar	2.30	.27	.43	3.10

⁽¹⁾ Can also be made available at other FPC locations (Bartow, Higgins and Avon Park). hourly rate is limited by tariff to 6% of daily volume.

⁽²⁾ Includes compressor fuel (3.14%), commodity charge, GRU transport charge (10¢) and other miscellaneous charges.

⁽³⁾ At 100% load factor.

FUELS SUPPLY DEPARTMENT

FCP 9401

NATURAL GAS

Delivered to Suwannee Plant

Available Firm Volume: 10,000 MMBTU/day⁽¹⁾

	<u>N. Gas into Southern N. Gas</u>	<u>Variable Transport Component⁽²⁾</u>	<u>Fixed Demand Chrg</u>	<u>Total Del'd Price⁽³⁾</u>
1994				
Jun - Sept	2.10	.13	.75	2.98
Oct - Dec	2.30	.13	.75	3.18
1995				
Jan - Mar	2.25	.13	.75	3.13

⁽¹⁾ Hourly flow is limited by tariff to 6% of daily volume.

⁽²⁾ Includes compressor fuel (3.1%), commodity charges and other miscellaneous charges on both Southern Natural Gas and South Georgia Natural Gas.

⁽³⁾ At 100% load factor.

Appendix II

FCP 9401

Forecasted Fuel Oil and Gas Forecast Assumptions

General

The oil and gas forecast is based on expectations of normal weather, no radical changes in world energy markets (OPEC actions, for example), governmental rule changes, etc. Prices forecasted have been levelized and don't reflect the normal daily market fluctuations and are based on current contract structures and specifications.

Oil

- (1) FPC Residual Fuel Oil (#6) and Distillate Fuel Oil (#2) Prices were derived from the PIRA Forecast dated 4/28/94 and the Chem Data Report dated April 1994 for the Gulf Coast (Chem Data sulfur grades forecasted were adjusted for sulfur grades used by FPC).
- (2) Transportation to the Tampa Bay area plus applicable environmental taxes were added to the above prices (an adjustment was later made in the transportation costs for individual plant locations when purchased from another location besides Tampa Bay). Bartow Terminal Channel Dredging assumed to offset any potential ocean transportation increases in early 1995.

Gas

- (1) Gas Prices at the Henry Hub location were derived by averaging the PIRA Forecast dated 5/10/94, the NYMEX as of 5/13/94 and the Chem Data Report dated April 1994. The Chem Data Report publishes a Gulf Coast Spot Price representing the West Texas area. Chem Data has estimated that 8 cents per MMBTU needs to be added to their Gulf Coast Spot Price to get an equivalent Henry Hub price.
- (2) The costs basis used to get an equivalent price, delivered into the Southern Natural Pipeline System compared to the Henry Hub location was a negative 2 cents per MMBTU. The cost basis used to deliver gas into Florida Gas Transmission Pipeline compared to the Henry Hub location was a positive 3 cents per MMBTU. (The basis was calculated using a 15 month history: 1/93 - 3/94).
- (3) Transportation costs from the Southern Natural Pipeline System to the Suwannee Plant and from the Florida Gas Transmission Pipeline to the University of Florida Cogeneration Project are based on their published tariff prices.

FUELS SUPPLY DEPARTMENT
FCP 9401
NUCLEAR FUEL EXPENSE PROJECTIONS

\$/MMBTU's

38

Does not include spent fuel disposal charges or enrichment plant decommissioning charges.⁽¹⁾

⁽¹⁾ Provided by Nuclear Operations

FCP9401.DW4

FUELS SUPPLY DEPARTMENT

FCP 9401

FUEL INVENTORY TARGET LEVELS

COAL⁽¹⁾

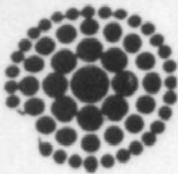
	<u>Inventory w/o</u> <u>Tank Bottoms</u>	<u>Tank Bottoms</u>	<u>Total Inventory</u>
RESIDUAL OIL (#6) BBLs.			
Ancote & Bartow S.	300,000	138,346	438,346
Bartow & Bartow N.	225,000	63,214	288,214
Suwannee 2.5%	30,000	12,088	42,088
Suwannee 1.0%	<u>40,000</u>	<u>8,192</u>	<u>48,192</u>
TOTAL	595,000	221,840	816,840

LIGHT OIL (#2) BBLs.

Avon Park	7,000	546	7,546
Bartow	28,440	6,762	35,202
Bayboro	25,000	6,522	31,522
Debary	65,721	34,279	100,000
Higgins	12,000	1,983	13,983
Intercession City	87,000	32,037	119,037
Port St. Joe	1,350	226	1,576
Rio Pinar	1,350	124	1,474
Suwannee	24,000	10,338	34,338
Turner	25,000	6,538	31,538
Start-up ⁽²⁾	<u>19,742</u>	<u>3,749</u>	<u>23,491</u>
TOTAL	296,603	103,104	399,707

⁽¹⁾ Dictated by delivery schedules

⁽²⁾ Ancote & Crystal River



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuel Supply Department
OFFICE

H2A
MAC

231-4537
TELEPHONE

SUBJECT: Fuel Cost Projections-FCP 9303

TO: Mr. Karl Wieland
Mr. Bob Niekum

DATE: December 20, 1993

Please find attached the Fuel Cost Projection FCP 9303. This forecast is for the fuel adjustment projection period April through September 1994.

If you have any questions or require additional information, please advise.

Dan Putnam
T. D. Putnam

TDP/jkv
Attachments:

cc: J. A. Hancock
N. L. Davis
L. D. Brousseau
T. L. Brier
M. B. Foley
D. E. Jones
R. D. Dolan
J. G. Keppeler
J. P. Lindquist
P. Z. McGovern
S. M. Miller
K. L. Anthony
D. D. Williams
D. M. Davis - Electric Fuels
Forecast Book
File

94- 9303

95 → 9302

DEC 21 1993

FUEL SUPPLY DEPARTMENT

FCP 9303

Fuel Price Projections

Coal

Coal Price Projections are provided by Electric Fuels Corporation and represent an estimate of EFC's price to Florida Power for coal delivered to the plant sites in accordance with the delivery schedules projected. It assumes environmental restrictions on coal quality remain in effect as per current plans: 2.1 lbs. per million BTU sulfur dioxide limit for C. R. 1 & 2 and 1.2 lbs per million BTU sulfur dioxide limit for C. R. 4 & 5.

FUEL SUPPLY DEPARTMENT
9303

Coal Price Projections
Average Prices

	<u>BTUs/lb</u>	<u>C. R. 1 & 2</u> <u>\$/ton</u>	<u>c/10⁶ BTUs</u>	<u>BTUs/lb</u>	<u>C. R. 4 & 5</u> <u>\$/ton</u>	<u>c/10⁶ BTUs</u>
<u>1993</u>						
DEC ⁽¹⁾	12,335 24,670	47.03	190.64	12,683 25,366	50.82	200.34

Projected Deliveries

Coal tons x 10³

	<u>C.R. 1 & 2</u>	<u>C.R. 4 & 5</u>
1993		
Dec ⁽²⁾	158	300

(1) Price taken from EFC Monthly Price Letters to Florida Power for December 1993.

(2) For 1994 Projected Deliveries see the attached Forecast from EFC dated 12/13/93.

TDP
December 1993

PROJ9303.DP3

ELECTRIC FUELS CORPORATION

ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (813) 824-6600

FILED
DEC 14 1993
FEDERAL BUREAU OF INVESTIGATION
U.S. DEPARTMENT OF JUSTICE

DEC 14 1993

RECEIVED

December 13, 1993

Mr. T. D. Putnam
Fuel Engineer
FLORIDA POWER CORPORATION
P. O. Box 14042
St. Petersburg, Florida 33733

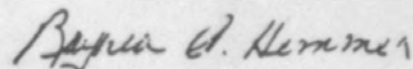
Dear Dan:

Attached are the 1994 coal price forecasts for Crystal River Units 1 & 2 (Attachment A), Crystal River Units 4 & 5 (Attachment B) and all units combined (Attachment C). These prices are for use in your April-September 1994 fuel-adjustment filing. We have based our calculations on the latest financial estimates for 1994 provided by our Accounting Department and the assumptions listed on Appendix I.

If you require additional information, please feel free to give me or Donna Davis a call.

Sincerely,

ELECTRIC FUELS CORPORATION



Raynia A. Hemmer
Contract Administration Specialist

RAH/ro

Attachments

cc: W. D. Carter
D. J. Clark, Jr.
D. G. Edwards
D. M. Davis
G. K. Orchard
D. D. Williams

ATTACHMENT A

**ELECTRIC FUELS CORPORATION
1994 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2**

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu	Incremental c/MMBtu
1994					
January	173	^{24.506} 12,253	44.86	183.04	163.16
February	163	^{24.516} 12,258	45.06	183.82	162.65
March	173	12,253	44.83	182.92	162.65
April	163	12,258	45.15	184.17	163.05
May	173	12,253	44.96	183.44	163.05
June	163	12,258	45.37	185.05	163.05
July	163	12,258	45.30	184.80	163.46
August	173	12,253	45.09	183.99	163.46
September	163	12,258	45.28	184.70	163.46
October	163	12,258	45.38	185.12	163.86
November	173	12,253	45.14	184.18	163.86
December	163	12,258	45.51	185.65	163.86

**ELECTRIC FUELS CORPORATION
1994 COAL-PRICE FORECAST
CRYSTAL RIVER 4 & 5**

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu	Incremental c/MMBtu
<u>1994</u>					
January	317	12,649	49.66	196.30	167.69
February	317	12,649	49.69	196.42	167.16
March	317	12,649	49.65	196.28	167.16
April	317	12,649	49.76	196.70	167.57
May	317	12,649	49.76	196.70	167.57
June	317	12,649	49.98	197.55	167.57
July	317	12,649	49.89	197.23	167.98
August	317	12,649	49.87	197.12	167.98
September	317	12,649	49.88	197.15	167.98
October	317	12,649	49.94	197.39	168.38
November	317	12,649	49.89	197.22	168.38
December	317	12,649	50.10	198.05	168.38

ELECTRIC FUELS CORPORATION
1994 COAL-PRICE FORECAST
CRYSTAL RIVER 1 & 2 and 4 & 5

	Tons (000s)	Btu/lb.	\$/Ton	Average c/MMBtu
<u>1994</u>				
January	489	12,510	47.97	191.72
February	479	12,516	48.13	192.26
March	489	12,510	47.95	191.67
April	479	12,516	48.20	192.54
May	489	12,510	48.07	192.12
June	479	12,516	48.41	193.40
July	479	12,516	48.34	193.09
August	489	12,510	48.18	192.58
September	479	12,516	48.32	193.01
October	479	12,516	48.39	193.32
November	489	12,510	48.21	192.71
December	479	12,516	48.55	193.93



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS

APRIL 1 - SEPTEMBER 30, 1994

Page 1 of 2

COAL COSTS

- COAL PRICES ARE FORECASTED BASED ON EFC'S EXISTING LONG-TERM COAL CONTRACT PRICES AND THEIR INDIVIDUAL ESCALATION PROVISIONS. INDIVIDUAL INDICES ARE ANNUALIZED BASED ON PERCENT CHANGES YEAR TO DATE AS OF OCTOBER 1993. THE FLORIDA PROGRESS CORPORATE ANNUAL PROFIT PLAN (THE PLAN) INFLATION ASSUMPTION OF 3.0% (LESS ANY FIXED, NON-ESCALATED PORTION) IS UTILIZED FOR CONTRACTS THAT HAVE MULTIPLE COMBINATIONS OF INDICES.
- ONE SMALL COAL CONTRACT EXPIRES DECEMBER 31, 1993 AND FORECASTED REPLACEMENT IS WITH SPOT COAL, AS WELL AS DEFERRED TONS FROM 1993. NO MARKET REOPENERS ARE APPLICABLE IN 1994.
- SPOT COAL PRICES ARE BASED ON FORECASTED MARKET PRICE PROJECTIONS COMPILED IN CONJUNCTION WITH THE FIELDSTON COMPANY'S (EFC'S COAL INDUSTRY CONSULTANTS) FUEL FORECAST PLANNING AND OTHER COAL MARKET INTELLIGENCE.
- THE UMWA STRIKE IS ASSUMED TO BE OVER WITH PRICES REDUCED TO ASSUMED LEVELS BY THE END OF THE FIRST QUARTER.

TRANSPORTATION COSTS

- TRANSPORTATION COSTS ARE PROJECTED RAIL AND WATERBORNE FREIGHT COSTS UNDER EXISTING CONTRACTS AND THE PROJECTED MIX OF THE TWO TRANSPORTATION MODES.
- RAIL FREIGHT PRICES ARE BASED ON THE CONTRACT ESCALATION PROVISIONS AT THE PLAN INFLATION ASSUMPTION OF 3.0% (LESS ANY FIXED, NON-ESCALATED PORTION).
- RAIL RATES ARE REDUCED TO REFLECT A SET OF THREE NEW LOCOMOTIVES FORECASTED TO BE IN PLACE AS OF FEBRUARY 1, 1994.
- ASSUMED \$2 PER TON LEASED RAILCAR COST FOR ADDITIONAL 200,000 TONS OVER 1994 ANNUAL PROFIT PLAN/AUGUST 1993 FUEL FORECAST ALL ALLOCATED TO CRYSTAL RIVER 4 AND 5.
- WATER FREIGHT IS ESTIMATED AT THE MARKET RATE ESCALATED AT FORECASTED ESCALATION OF THE INDIVIDUAL INDICES IN ACCORDANCE WITH ESCALATION PROVISIONS OF THE WATERBORNE COMPONENT.



APPENDIX I

EFC FUEL ADJUSTMENT FORECAST ASSUMPTIONS

APRIL 1 - SEPTEMBER 30, 1994

Page 2 of 2

GENERAL AND ADMINISTRATION

- 1994 ANNUAL PROFIT PLAN G & A COSTS ASSUMED EXCEPT FOR PROFESSIONAL FEES WHICH WERE LEFT AT AUGUST 1993 FUEL FORECAST LEVEL.
- 37 PERCENT EFFECTIVE TAX RATE ASSUMED FOR INCOME TAX CALCULATION.

TONNAGE

- TONS ARE BASED ON LETTER FROM FPC DATED DECEMBER 2, 1993, WHICH REFLECTED A TOTAL REQUIREMENT OF 5,800,000 TONS.
- CONTRACT TONNAGE INCLUDES 379,000 TONS DEFERRED FROM 1993 TO 1994.

*EFC/RAH
12/16/93*

FUEL SUPPLY DEPARTMENT

Fuel Cost Projections - FCP 9303

Residual Oil & Distillate Oil

The major assumptions influencing the price forecast FCP 9303 include:

State and Federal Policies

State and Federal Policies are not expected to impact the residual or distillate oil market except that environmental restrictions will increase the relative demand and price of lower sulfur oils. World crude oil prices will remain vulnerable to geo-political and global economic impacts. Price volatility will be sensitive to macro changes to domestic legislation and regulation along with mid-eastern political and economic variables.

Residual & Distillate Oil Supply/Demand

Fuel oil demand will be flat to up as the demand for lower sulfur residual oil will grow and displace the demand for higher sulfur product.

Other Factors

Balances between the two above factors combined with uncertain weather patterns will cause periodic dislocation in supply/demand equilibrium and wider short term fluctuations in supply availability and prices than are presented in this projection.

Note: For additional assumptions used for this forecast please see Appendix II.

TDP
December 1993

PROJ9303.DP3

FUEL SUPPLY DEPARTMENT

FCP 9303

Residual Fuel Oil Price Projections

STEAM

	2.5% Sulfur		1.0% Sulfur	
	<u>\$/bbl.</u>	<u>¢/10⁶ BTUs⁽¹⁾</u>	<u>\$/bbl</u>	<u>¢/10⁶ BTUs⁽¹⁾</u>
<u>1993</u>				
Dec	9.88	156.8	11.66	185.1
<u>1994</u>				
Jan - Mar	9.88	156.8	13.10	207.9
Apr - Jun	9.70	154.0	12.42	197.1
Jul - Sept	11.24	178.4	13.99	222.1
Oct - Dec	12.95	205.6	15.92	252.7

⁽¹⁾ 6.3 X 10⁶ BTUs/bbl.

Note: 1995 and beyond use FPC 9302

FUEL SUPPLY DEPARTMENT

FCP 9303

#2 Fuel Oil Price Projections

	<u>\$/bbl.</u>	<u>¢/gal.</u>	<u>¢/10⁶ BTUs⁽¹⁾</u>
<u>1993</u>			
Dec	20.16	48.0	347.6
<u>1994</u>			
Jan - Mar	21.00	50.0	362.1
Apr - Jun	20.66	49.2	356.2
Jul - Sept	21.42	51.0	369.3
Oct - Dec	23.52	56.0	405.5

⁽¹⁾ 5.8 X 10⁶ BTUs/bbl. & 42 gal. per barrel

Note: 1995 and beyond use FCP 9302

FUEL SUPPLY DEPARTMENT

FCP 9303

Transportation Costs

<u>1994</u>		<u>\$/bbl.</u>	<u>¢/10⁶ BTUs⁽³⁾</u>
<u>Fuel</u>	<u>Location</u>	<u>Transportation</u>	
Resid. ⁽¹⁾	Suwannee	4.11	✓ 65.24
Dist. ⁽²⁾	Avon Park	1.09	✓ 18.79
	Bartow-barge	0.60	✓ 10.34
	Bayboro-barge	0.60	✓ 10.34
	DeBary	1.38	✓ 23.79
	Higgins	0.61	✓ 10.52
	Intercession City	0.50/bbl ⁽⁴⁾	✓ 8.62 ⁽⁴⁾
	Port St. Joe	1.29	✓ 22.24
	Rio Pinar	0.89	✓ 15.34
	Suwannee	1.24	✓ 21.38
	Turner	1.24	✓ 21.38
	Univ. of Florida	1.22	✓ 21.03

(1) 6.3 X 10⁶ BTU/bbl.

(2) 5.8 X 10⁶ BTU/bbl.

(3) Rounded to nearest 1/100 of a cent

(4) This price only includes the variable cost and excludes the fixed tank leasing cost of \$24,000/month

Note: 1995 and beyond use FCP 9302

TDP
December 1993

PROJ9303.DP3

FUEL SUPPLY DEPARTMENT
Fuel Cost Projections - FCP 9303

Natural Gas

Interruptible

Interruptible gas is currently available only on an "as if and when" basis. Such gas is not expected to be available in significant and reliable quantities in the future.

Firm Transportation

Florida Power has a firm transportation (FT) contract with Florida Gas Transmission for the University of Florida Project. FT for the Suwannee Plant using the Southern Natural and South Georgia Natural pipelines is projected to be concluded by the end of May 1994.

Note: For additional assumptions used for this forecast, please see Appendix II.

FUEL SUPPLY DEPARTMENT

FCP 9303

University of Florida Gas

Available Volume 10⁶ BTUs

8,800/day⁽¹⁾

Price ¢/10⁶ BTUs

	Gas Price Delv'd into FGT Pipeline	Transportation Cost on FGT Pipeline		Transportation Cost on GRU Pipeline Variable Cost	Delv'd Price to Univ. of Fla.
		Variable Cost ⁽²⁾	Fixed Demand Charge		
<u>1993</u>					
Dec 187	17	43	10	<u>TOTAL VAR</u> 214	257
<u>1994</u>					
Jan- Mar 187	17	43	10	214	257
Apr- Jun 190	16	43	10	206	249
Jul- Sept 191	17	43	10	218	261
Oct- Dec 206	17	43	10	233	276

(1) Gas flow hourly limit is equal to 6% of daily volume.

(2) Included in the variable cost is the cost of compressor fuel used for transportation (3.0% of the Gas Price delv'd into the FGT Pipeline).

Note: 1995 and beyond use FPC 9302

FUEL SUPPLY DEPARTMENT

FCP 9303

Suwannee Plant Gas

Available Volume 10^6 BTUs

10,000/day beginning 5/94 ⁽¹⁾

Price ¢/ 10^6 BTUs

	Gas Price Delv'd into Southern Natural Pipeline	Transportation Cost on Southern & South Georgia Pipelines Variable Cost ⁽²⁾	Fixed Demand Charge	TOTAL VAR.	Delv'd Price to Suwannee Plant
<u>1994</u>					
May-Jun	186	25	58	211	269
Jul-Sept	197	25	58	222	280
Oct-Dec	212	26	58	238	296

(1) Gas flow hourly limit is equal to 6% of daily volume.

(2) Included in the variable cost is the cost of compressor fuel used for transportation (3.1% of the Gas Price delv'd into the Southern Natural Pipeline)

Note: 1995 and beyond use FCP 9302

FUEL SUPPLY DEPARTMENT

FCP 9303

Coal and Oil Projected Inspection Costs*

Coal Inspection Services*

(1993) Dec	\$17,300 per month average
1994	Escalate with general inflation.

Petroleum Inspection Cost*

(1993) Dec	\$ 9,300 per month average
1994	Escalate with general inflation.

* Charged directly to FPC Fuel Costs.

FCP - 9303
Strategic Plan
Estimated Fuel Inventory Targets for 1994 - 1998*

Residual Oil Steam (bbbls)	Inventory Target w/o M.O.L.	Minimum Operating Level	Inventory Target w/ M.O.L.	Inventory Variance
Anclole & B. S.	432,000	138,346	561,346	
Bartow & B. N.	243,000	63,214	306,214	
Suwannee 1&2	30,000	12,088	42,088	
Suwannee 3	16,000	8,192	24,192	
TOTAL STEAM	712,000	221,840	933,840	114,630
Distillate Oil				
Peaking (bbbls)				
Avon Park	8,000	546	8,546	
Bartow	28,200	6,762	34,962	
Bayboro	25,000	6,522	31,522	
Debary	98,000	34,279	132,279	
Higgins	12,500	1,983	14,483	
Intercession City	87,000	32,037	119,037	
Port St. Joe	1,350	226	1,576	
Rio Pinar	1,350	124	1,474	
Suwannee	24,000	10,338	34,338	
Turner	30,500	6,538	37,038	
Sub. Total	315,900	99,355	415,255	
Start-Up (bbbls)				
Anclole	7,466	1,008	8,474	
Bartow	300	203	503	
C.R. 1 & 2	3,742	558	4,300	
C.R. 4 & 5	8,229	1,216	9,445	
C. R. 3	300	967	1,267	
TOTAL DISTILLATE	456,540	119,431	575,971	38,034
Coal				
C.R. 1 & 2	215,000	0	215,000	
C.R. 4 & 5	430,000	0	430,000	
TOTAL COAL (tons)	645,000	0	645,000	135,151

* Potential further reductions after N. Gas conversion at Anclole, assume 100,000 BBLs.

DDW - 10/18/93
PROJ9303.XLS

Appendix II

FCP 9303

Forecasted Fuel Oil and Gas Forecast Assumptions

- Oil (1) FPC Residual Fuel Oil and Distillate Fuel Oil Prices were derived by averaging the PIRA Forecast dated 12/8/93 and the Chem Data Report dated November/December 1993 for the Gulf Coast (Chem Data sulfur grades forecasted were adjusted for sulfur grades used by FPC). Because of recent oil price decreases, Chem Data reduced their published forecasted prices \$2.00 per barrel when contacted by phone on 12/16/93.
- (2) Transportation to the Tampa Bay area plus applicable environmental taxes were added to the above prices (an adjustment was later made in the transportation costs for individual plant locations when purchased from another location besides Tampa Bay).
- Gas (1) Gas Prices at the Henry Hub location were derived by averaging the PIRA Forecast dated 12/15/93, the NYMEX as of 12/15/93 and the Chem Data Report dated November/December 1993. The Chem Data Report publishes a Gulf Coast Spot Price representing the West Texas area. Chem Data has determined 8 cents per MMBTU needs to be added to their Gulf Coast Spot Price to get an equivalent Henry Hub price.
- (2) The costs basis used to get an equivalent price, delivered into the Southern Natural Pipeline System compared to the Henry Hub location was a negative 6 cents per MMBTU. The cost basis used to deliver gas into Florida Gas Transmission Pipeline compared to the Henry Hub location was a negative 12 cents per MMBTU.
- (3) Transportation costs from the Southern Natural Pipeline System to the Suwannee Plant and from the Florida Gas Transmission Pipeline to the University of Florida Cogeneration Project are based on their published tariff prices.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuel Supply Department
OFFICE

H2A
MAC

231-4532
TELEPHONE

SUBJECT: 1993 Integrated Resource Study

TO: R. D. Niekum

DATE August 16, 1993

As per your request of June 10, 1993 and July 9, 1993 please find attached the Base Case Fuel Forecast (FCP 9302).

Dale Williams

cc: J. A. Hancock

AUG 16 1993

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES

1994 - 1998

CRYSTAL RIVER 1 & 2

	Tons (000s)	Btu/lb	\$/Ton	Average \$/Mbtu
1994: January - December	<u>2,000</u>	<u>12,256</u>	<u>45.42</u>	<u>1.86</u>
1995: January - December	<u>1,750</u>	<u>12,386</u>	<u>45.86</u>	<u>1.85</u>
1996: January - December	<u>1,850</u>	<u>12,500</u>	<u>44.96</u>	<u>1.80</u>
1997: January - December	<u>1,850</u>	<u>12,500</u>	<u>46.01</u>	<u>1.84</u>
1998: January - December	<u>1,900</u>	<u>12,500</u>	<u>46.84</u>	<u>1.87</u>

Escalate at 80% of inflation after 1998

EFC/DGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES

1994 - 1998

CRYSTAL RIVER 4 & 5

	Tons (000s)	Btu/lb	\$/Ton	Average \$/Mbtu
1994: January - December	<u>3,700</u>	<u>12,645</u>	<u>49.76</u>	<u>1.97</u>
1995: January - December	<u>3,600</u>	<u>12,653</u>	<u>50.55</u>	<u>2.00</u>
1996: January - December	<u>3,450</u>	<u>12,659</u>	<u>52.80</u>	<u>2.09</u>
1997: January - December	<u>3,700</u>	<u>12,649</u>	<u>54.13</u>	<u>2.14</u>
1998: January - December	<u>3,750</u>	<u>12,647</u>	<u>55.84</u>	<u>2.21</u>

Escalate at 80% of inflation after 1998

EFC/DGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES

1994 - 1998

TOTAL CRYSTAL RIVER 1 & 2 AND 4 & 5

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,509</u>	<u>48.24</u>	<u>1.93</u>
1995: January - December	<u>12,565</u>	<u>49.02</u>	<u>1.95</u>
1996: January - December	<u>12,604</u>	<u>50.06</u>	<u>1.99</u>
1997: January - December	<u>12,599</u>	<u>51.42</u>	<u>2.04</u>
1998: January - December	<u>12,597</u>	<u>52.81</u>	<u>2.10</u>

Escalate at 80% of inflation after 1998

EFC/DGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED INCREMENTAL COAL PRICES

1994 - 1998

CRYSTAL RIVER 1 & 2

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,500</u>	<u>41.05</u>	<u>1.64</u>
1995: January - December	<u>12,500</u>	<u>42.65</u>	<u>1.71</u>
1996: January - December	<u>12,500</u>	<u>43.77</u>	<u>1.75</u>
1997: January - December	<u>12,500</u>	<u>44.65</u>	<u>1.79</u>
1998: January - December	<u>12,500</u>	<u>45.55</u>	<u>1.82</u>

Escalate at 80% of inflation after 1998

EFC/EGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED INCREMENTAL COAL PRICES

1994 - 1998

CRYSTAL RIVER 4 & 5

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,500</u>	<u>42.18</u>	<u>1.69</u>
1995: January - December	<u>12,500</u>	<u>43.04</u>	<u>1.72</u>
1996: January - December	<u>12,500</u>	<u>44.42</u>	<u>1.78</u>
1997: January - December	<u>12,500</u>	<u>45.80</u>	<u>1.83</u>
1998: January - December	<u>12,500</u>	<u>47.20</u>	<u>1.89</u>

Escalate at 80% of inflation after 1998

EFC/DGE
8/12/93

2X 1-2

CR 4-5

HS

LS

ELECTRIC FUELS CORPORATION

FPC 9302

High Sulfur Coal - Base Case

Delivered to Central Florida Location

	<u>\$/MMBTU</u>
1994	1.74
1995	1.72
1996	1.73
1997	1.75
1998	1.76
1999 and beyond	escalate at 80% of inflation

HEAT Content = 12,500 Btu/lb

Sulfur Content = 1.5 - 2.0%

FUEL SUPPLY DEPARTMENT

FCP 9302

Orimulsion - Base Case

Delivered to Central Florida Location

	<u>\$/MMBTU</u>
1994	1.70
1995	1.75
1996	1.80
1997	1.86
1998	1.91
1999 and beyond	escalate with general inflation

units = bbls

Heat content = 4.4 (FROM 1991 FAC. STUDY)

ESCAL = SAME AS OIL

FUEL SUPPLY DEPARTMENT

FCP 9302

Petroleum Coke - Base Case

Delivered to Central Florida Location

	<u>\$/MMBTU</u>
1994	1.10
1995	1.16
1996	1.21
1997	1.27
1998	1.33
1999	and beyond escalate with general inflation

UNITS = TONS
HEAT CONTENT = 14,000 BTU/lb = 28.0 _{MMBTU/TON} > PER DAN P.
8/30/93
ESCAL = DAN WAS NOT SURE
HOW TO ESCAL. THIS
FUEL
(ESCAL LIKE COAL)

FUEL SUPPLY DEPARTMENT

FCP 9302

SunShine Pipeline Gas - Base Case

Available Volume MMBTU's⁽¹⁾

Anclote 120,000/day beginning 1/98 Year round with additional 20,000/day May - September

Polk 1 45,000/day beginning 8/98

Polk 2 45,000/day beginning 8/99

Price \$/MMBTU's

	<u>Gas Cost</u>	<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
1996	2.50	.07	.73
1997	2.55	.07	.74
1998	2.65	.08	.75
1999	2.85	.08	.75
2000	3.00	.08	.76
2001	3.15	.09	.76
2002	3.35	.09	.77
2003	3.50	.10	.77
2004	3.70	.10	.77

2005 and beyond escalate Gas Cost and Variable Cost with general inflation and Fixed Demand Charge at 1/2 the rate of general inflation.

*Fuel escalation
D.N. 5/24/03*

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity

FUEL SUPPLY DEPARTMENT

FCP 9302

University of Florida Gas - Base Case

8,800/day beginning 11/93⁽¹⁾

Available Volume MMBTU's

Price \$/MMBTU's

	<u>Gas Cost</u>	<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
1994	2.40	.32	.48
1995	2.45	.33	.47
1996	2.50	.35	.47
1997	2.55	.36	.48
1998	2.65	.37	.48
1999	2.85	.39	.49
2000	3.00	.40	.49
2001	3.15	.42	.50
2002	3.35	.43	.50
2003	3.50	.45	.51
2004	3.70	.47	.51

2005 and beyond escalate Gas Cost and Variable Transportation with general inflation and Fixed Demand Charge at 1/2 the rate of general inflation.

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity.

FUEL SUPPLY DEPARTMENT

FCP 9302

Suwannee Plant Gas - Base Case

10,000/day beginning 5/94⁽¹⁾

Available Volume MMBTU's

Price \$/MMBTU's

	<u>Gas Cost</u>	<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
			.53
		.27	
1994	2.40	.28	.54
1995	2.45	.29	.54
1996	2.50	.30	.55
1997	2.55	.32	.55
1998	2.65	.33	.56
1999	2.85	.34	.56
2000	3.00	.35	.57
2001	3.15	.36	.57
2002	3.35	.37	.58
2003	3.50	.38	.58
2004	3.70		

2005 and beyond escalate Gas Cost and Variable Transportation with general inflation and fixed Demand Charge at 1/2 the rate of general inflation.

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity.

FUEL SUPPLY DEPARTMENT

FCP 9302

Nuclear Fuel Expense Projections - Base Case

\$/MMBTU's

Cycle 9 (current cycle)

.47

Future cycles escalate with general inflation.

FUEL SUPPLY DEPARTMENT

FCP 9302

Residual Fuel Oil Price Projection - Base Case

STEAM

2.5% SULFUR			1.0% SULFUR	
	<u>\$/BBL</u>	<u>\$/MMBTU's⁽¹⁾</u>	<u>\$/BBL</u>	<u>\$/MMBTU's⁽¹⁾</u>
1994	15.00	2.38	18.00	2.86
1995	16.00	2.54	19.00	3.02
1996	17.00	2.70	21.00	3.33
1997	18.00	2.86	23.00	3.65
1998	19.00	3.02	25.00	3.97
1999	20.00	3.17	26.00	4.13
2000	21.00	3.33	28.00	4.44
2001	22.00	3.49	29.00	4.60
2002	23.00	3.65	30.00	4.76
2003	24.00	3.81	31.00	4.92
2004	25.00	3.98	32.00	5.08

2005 and beyond escalate with general inflation.

⁽¹⁾ 6.3 MMBTU/bbl.

FUEL SUPPLY DEPARTMENT

FCP 9302

#2 Fuel Oil Price Projection - Base Case

	<u>\$/bbl.</u>	<u>¢/gal.</u>	<u>\$/MMBTU's⁽¹⁾</u>
1994	27.30	65	4.71
1995	29.40	70	5.07
1996	31.08	74	5.36
1997	33.18	78	5.72
1998	34.44	82	5.94
1999	36.12	86	6.23
2000	38.22	91	6.59
2001	39.90	95	6.88
2002	41.58	99	7.17
2003	43.26	103	7.45
2004	44.94	107	7.75

2005 and beyond escalate with general inflation

⁽¹⁾ 5.8 MMBTU/bbl. and 42 gal. per barrel.

FUEL SUPPLY DEPARTMENT

FCP 9302

Fuel Oil Transportation Costs - Base Case

1994

\$/bbl

<u>Fuel</u>	<u>Location</u>	<u>Transportation</u>	<u>\$/MMBTU's⁽¹⁾</u>
⁽²⁾ Resid	Higgins	0.57	.09
	Suwannee	1.93	.31
	Turner	1.49	.24
⁽³⁾ Dist.	Avon Park	1.23	.21
	Bartow-barge	0.38	.07
	Bayboro-barge	0.38	.07
	DeBary	2.00	.35
	Higgins	0.60	.10
	Intercession City	1.33	.23
	Port St. Joe	1.29	.22
	Rio Pinar	1.10	.19
	Suwannee	1.20	.21
	Turner-barge	1.38	.24
	University of Florida	1.22	.21

1995 and beyond escalate with general inflation

⁽¹⁾ Rounded to nearest cent.

⁽²⁾ 6.3 MMBTU/bbl.

⁽³⁾ 5.8 MMBTU/bbl.

FINANCIAL ASSUMPTIONS FOR 1994 I.R.P.

	CURRENT PROSCREEN VALUES	1994 I.R.P. BASE VALUES		
		1994-2004	2005-2017	2018 +
CER Inputs				
DISCOUNT RATE	8.99%	8.95%	8.95%	8.95%
FED INC TAX RATE	37.63%	38.58%	38.58%	38.58%
INFLATION RATE	0.00%	0.00%	0.00%	0.00%
AFUDC RATE	10.43%	9.00%	9.00%	9.00%
CAPITALIZED INT DEBT RATE	8.50%	8.50%	8.30%	8.00%
DEBT STRUCTURE BOOK	45.00%	45.00%	45.00%	45.00%
DEBT STRUCTURE FOR TAX	100.00%	100.00%	100.00%	100.00%
DESIRED RETURN ON RATE BASE	12.00%	10.42%	10.42%	10.42%
ITC RATE	0.00%	0.00%	0.00%	0.00%
LONG TERM DEBT INT RATE	8.50%	8.50%	8.30%	8.00%
COST OF CAP ESC RATE (Coal)	4.50%	4.35%	4.30%	4.30%
COST OF CAP ESC RATE (C.T.)		4.06%	3.80%	3.80%
COST OF CAP ESC RATE (C.C.)		4.35%	4.30%	4.30%
PRV Inputs				
FUEL COST ESCALATION (Nuclear)	4.90%	N/A	2.80%	2.80%
FUEL COST ESCALATION (Coal)		N/A	2.80%	2.80%
FUEL COST ESCALATION (Oil)		N/A	3.50%	3.50%
FUEL COST ESCALATION (Gas)		N/A	3.50%	3.50%
ENERGY COST ESCALATION	4.90%	N/A	0.00%	0.00%
FIXED COST ESCALATION	4.50%	3.15%	3.50%	3.50%
VARIABLE COST ESCALATION	4.50%	3.15%	3.50%	3.50%
REVENUE DISCOUNT RATE	8.99%	8.95%	8.95%	8.95%
SALES DISCOUNT RATE	10.43%	0.00%	0.00%	0.00%
WEIGHTED COST OF CAPITAL	8.99%	10.42%	10.42%	10.42%
CONSTRUCTION ESCALATION (Coal)	4.50%	4.35%	4.30%	4.30%
CONSTRUCTION ESCALATION (C.T.)	4.50%	4.06%	3.80%	3.80%
CONSTRUCTION ESCALATION (C.C.)	15.34%	4.35%	4.30%	4.30%
LEVELIZED CHARGE RATE (Coal)	15.34%	13.68%	13.68%	13.68%
LEVELIZED CHARGE RATE (C.T.)	15.34%	15.29%	15.29%	15.29%
LEVELIZED CHARGE RATE (C.C.)	15.34%	14.17%	14.17%	14.17%
DSV Inputs				
BASE REVENUE ESCALATION	4.50%	2.00%	2.70%	2.70%
CUSTOMER COST ESCALATION	4.50%	3.60%	3.70%	3.50%
DSM EXPENSE ESCALATION	4.50%	3.60%	3.70%	3.50%
Memo GENERAL INFLATION (CPI)				
Memo IMPLICIT PRICE DEFLATOR (for fuel escalation)				
		3.60%	3.70%	3.50%
		3.15%	3.50%	3.50%

COAL 49-2004

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES

1994 - 1998

CRYSTAL RIVER 1 & 2

	Tons (000s)	Btu/lb	\$/Ton	Average \$/Mbtu
1994: January - December	<u>2,000</u>	<u>12,256</u> 24.51	<u>45.42</u>	<u>1.86</u>
1995: January - December	<u>1,750</u>	<u>12,386</u> 24.77	<u>45.86</u>	<u>1.85</u>
1996: January - December	<u>1,850</u>	<u>12,500</u> 25.00	<u>44.96</u>	<u>1.80</u>
1997: January - December	<u>1,850</u>	<u>12,500</u> 25.00	<u>46.01</u>	<u>1.84</u>
1998: January - December	<u>1,900</u>	<u>12,500</u> 25.00	<u>46.84</u>	<u>1.87</u>

Escalate at 80% of inflation after 1998

EFC/DGE

8/12/93

FCP 9302 Base Case
ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES
1994 - 1998
CRYSTAL RIVER 4 & 5

	Tons (000s)	Btu/lb	\$/Ton	Average \$/Mbtu
1994: January - December	<u>3,700</u>	<u>12,645</u> 25.29	<u>49.76</u>	<u>1.97</u>
1995: January - December	<u>3,600</u>	<u>12,653</u> 25.31	<u>50.55</u>	<u>2.00</u>
1996: January - December	<u>3,450</u>	<u>12,659</u> 25.32	<u>52.80</u>	<u>2.09</u>
1997: January - December	<u>3,700</u>	<u>12,649</u> 25.30	<u>54.13</u>	<u>2.14</u>
1998: January - December	<u>3,750</u>	<u>12,647</u> 25.29	<u>55.84</u>	<u>2.21</u>

Escalate at 80% of inflation after 1998

EFC/DGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED COAL PRICES

1994 - 1998

TOTAL CRYSTAL RIVER 1 & 2 AND 4 & 5

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,509</u>	<u>48.24</u>	<u>1.93</u>
1995: January - December	<u>12,565</u>	<u>49.02</u>	<u>1.95</u>
1996: January - December	<u>12,604</u>	<u>50.06</u>	<u>1.99</u>
1997: January - December	<u>12,599</u>	<u>51.42</u>	<u>2.04</u>
1998: January - December	<u>12,597</u>	<u>52.81</u>	<u>2.10</u>

Escalate at 80% of inflation after 1998

EFC/DGE

8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED INCREMENTAL COAL PRICES
1994 - 1998
CRYSTAL RIVER 1 & 2

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,500</u>	<u>41.05</u>	<u>1.64</u>
1995: January - December	<u>12,500</u>	<u>42.65</u>	<u>1.71</u>
1996: January - December	<u>12,500</u>	<u>43.77</u>	<u>1.75</u>
1997: January - December	<u>12,500</u>	<u>44.65</u>	<u>1.79</u>
1998: January - December	<u>12,500</u>	<u>45.55</u>	<u>1.82</u>

Escalate at 80% of inflation after 1998

EFC/EGE
8/12/93

FCP 9302 Base Case

ELECTRIC FUELS CORPORATION

ESTIMATED INCREMENTAL COAL PRICES

1994 - 1998

CRYSTAL RIVER 4 & 5

	Btu/Lb.	\$/Ton	Average \$/Mbtu
1994: January - December	<u>12,500</u>	<u>42.18</u>	<u>1.69</u>
1995: January - December	<u>12,500</u>	<u>43.04</u>	<u>1.72</u>
1996: January - December	<u>12,500</u>	<u>44.42</u>	<u>1.78</u>
1997: January - December	<u>12,500</u>	<u>45.80</u>	<u>1.83</u>
1998: January - December	<u>12,500</u>	<u>47.20</u>	<u>1.89</u>

Escalate at 80% of inflation after 1998

EFC/DGE

8/12/93

ELECTRIC FUELS CORPORATION

FPC 9302

High Sulfur Coal - Base Case

Delivered to Central Florida Location

	<u>\$/MMBTU</u>
1994	1.74
1995	1.72
1996	1.73
1997	1.75
1998	1.76
1999 and beyond	escalate at 80% of inflation

FUEL SUPPLY DEPARTMENT

FCP 9302

Orimulsion - Base Case

Delivered to Central Florida Location

	<u>\$/MMBTU</u>
1994	1.70
1995	1.75
1996	1.80
1997	1.86
1998	1.91
1999 and beyond	escalate with general inflation

FUEL SUPPLY DEPARTMENT

FCP 9302

Petroleum Coke - Base Case
Delivered to Central Florida Location

	<u>\$/MMBTU</u>
	1.10
1994	1.16
1995	1.21
1996	1.27
1997	1.33
1998	
1999	and beyond escalate with general inflation

FUEL SUPPLY DEPARTMENT

FCP 9302

Residual Fuel Oil Price Projection - Base Case

STEAM

	2.5% SULFUR		1.0% SULFUR	
	<u>\$/BBL</u>	<u>\$/MMBTU's⁽¹⁾</u>	<u>\$/BBL</u>	<u>\$/MMBTU's⁽¹⁾</u>
1994	15.00	2.38	18.00	2.86
1995	16.00	2.54	19.00	3.02
1996	17.00	2.70	21.00	3.33
1997	18.00	2.86	23.00	3.65
1998	19.00	3.02	25.00	3.97
1999	20.00	3.17	26.00	4.13
2000	21.00	3.33	28.00	4.44
2001	22.00	3.49	29.00	4.60
2002	23.00	3.65	30.00	4.76
2003	24.00	3.81	31.00	4.92
2004	25.00	3.96	32.00	5.08

2005 and beyond escalate with general inflation.

⁽¹⁾ 6.3 MMBTU/bbl.

FUEL SUPPLY DEPARTMENT

FCP 9302

#2 Fuel Oil Price Projection - Base Case

	<u>\$/bbl.</u>	<u>¢/gal.</u>	<u>\$/MMBTU's⁽¹⁾</u>
		65	4.71
1994	27.30	70	5.07
1995	29.40	74	5.36
1996	31.08	78	5.72
1997	33.18	82	5.94
1998	34.44	86	6.23
1999	36.12	91	6.59
2000	38.22	95	6.88
2001	39.90	99	7.17
2002	41.58	103	7.45
2003	43.26	107	7.75
2004	44.94		

2005 and beyond escalate with general inflation

⁽¹⁾ 5.8 MMBTU/bbl. and 42 gal. per barrel.

FUEL SUPPLY DEPARTMENT

FCP 9302

University of Florida Gas - Base Case

Available Volume MMBTU's

8,800/day beginning 11/93⁽¹⁾

Price \$/MMBTU's

		<u>Gas Cost</u>	<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
1994	2.72	2.40		
1995	2.78	2.45	.32	.46
1996	2.85	2.50	.33	.47
1997	2.91	2.55	.35	.47
1998	3.02	2.65	.36	.48
1999	3.24	2.85	.37	.48
2000	3.40	3.00	.39	.49
2001	3.57	3.15	.40	.49
2002	3.78	3.35	.42	.50
2003	3.95	3.50	.43	.50
2004	4.17	3.70	.45	.51
			.47	.51

2005 and beyond escalate Gas Cost and Variable Transportation with general inflation and Fixed Demand Charge at 1/2 the rate of general inflation.

Fuel escalation

per Dale Williams 8/23

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity.

FUEL SUPPLY DEPARTMENT

9302
FCP 0203

Suwannee Plant Gas - Base Case

Available Volume MMBTU's

10,000/day beginning 5/94⁽¹⁾

Price \$/MMBTU's

	<u>Gas Cost</u>		<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
1994	2.40	2.67	.27	.53
1995	2.45	2.73	.28	.54
1996	2.50	2.79	.29	.54
1997	2.55	2.85	.30	.55
1998	2.65	2.97	.32	.55
1999	2.85	3.18	.33	.56
2000	3.00	3.34	.34	.56
2001	3.15	3.50	.35	.57
2002	3.35	3.71	.36	.57
2003	3.50	3.87	.37	.58
2004	3.70	4.08	.38	.58

2005 and beyond escalate Gas Cost and Variable Transportation with general inflation and fixed Demand Charge at 1/2 the rate of general inflation.

FUEL

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity.

FUEL SUPPLY DEPARTMENT

FCP 9302

SunShine Pipeline Gas - Base Case

Available Volume MMBTU's⁽¹⁾

Anclote 120,000/day beginning 1/96 Year round with additional 20,000/day May - September

Polk 1 45,000/day beginning 8/98

Polk 2 45,000/day beginning 8/99

Price \$/MMBTU's

		<u>Gas Cost</u>	<u>Variable Transportation</u>	<u>Fixed Demand Charge</u>
1996	2.57	2.50	.07	.73
1997	2.62	2.55	.07	.74
1998	2.73	2.65	.08	.75
1999	2.93	2.85	.08	.75
2000	3.08	3.00	.08	.76
2001	3.24	3.15	.09	.78
2002	3.44	3.35	.09	.77
2003	3.60	3.50	.10	.77
2004	3.80	3.70	.10	.77

2005 and beyond escalate Gas Cost and Variable Cost with general inflation and Fixed Demand Charge at 1/2 the rate of general inflation.
FUEL

⁽¹⁾ Hourly Flow Limit is 6% of daily quantity

FUEL SUPPLY DEPARTMENT

FCP 9302

Fuel Oil Transportation Costs - Base Case

1994

\$/bbl

<u>Fuel</u>	<u>Location</u>	<u>Transportation</u>	<u>\$/MMBTU's⁽¹⁾</u>
⁽²⁾ Resid	Higgins	0.57	.09
	Suwannee	1.93	.31
	Turner	1.49	.24
⁽³⁾ Dist.	Avon Park	1.23	.21
	Bartow-barge	0.38	.07
	Bayboro-barge	0.38	.07
	DeBary	2.00	.35
	Higgins	0.60	.10
	Intercession City	1.33	.23
	Port St. Joe	1.29	.22
	Rio Pinar	1.10	.19
	Suwannee	1.20	.21
	Turner-barge	1.38	.24
	University of Florida	1.22	.21

1995 and beyond escalate with general inflation

⁽¹⁾ Rounded to nearest cent.

⁽²⁾ 6.3 MMBTU/bbl.

⁽³⁾ 5.8 MMBTU/bbl.

FUEL SUPPLY DEPARTMENT

FCP 9302

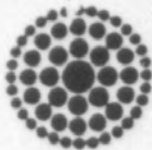
Nuclear Fuel Expense Projections - Base Case

\$/MMBTU's

Cycle 9 (current cycle)

.47

Future cycles escalate with general inflation.



**Florida
Power**
CORPORATION

INTEROFFICE CORRESPONDENCE

Fuel & Special Projects

H-2-A

4537

Office

MAC

Telephone

SUBJECT: Special Fuel Forecast - Facility Planning Case

TO: Mr. Jerry Tang

DATE: April 6, 1990

Attached is a fuel forecast that is to replace the base forecast sent to you on March 9, 1990 by Dale Williams. This new base case reflects the impact of the "Acid Rain" legislation currently being considered by Congress. It is assumed that this legislation would create a larger demand and therefore higher prices for low sulfur fuels.

The low and high fuel forecasts in the March 9th transmittal are still valid and are to be used with the above base case. Also, the gas prices given in FCP 8904 are to be used prior to 1994. After 1994 the New Pipeline Source forecast attached is to be used for all gas requirements (for interruptible gas the fixed cost is to be added to the variable cost).

If you have any questions or require additional information, please advise.

T. D. Putnam
T. D. Putnam

TDP/jlc
Attachments

cc: Mr. D. J. Rowland
Mr. D. D. Williams
Mr. D. E. Jones

RECEIVED
System Planning

APR 9 1990

FUEL & SPECIAL PROJECTS

Special Fuel Forecast - Facility Planning Case - Base Case

Coal Price Projections

Average Prices

<u>C. R. 1 & 2</u>			<u>C. R. 4 & 5</u>		
<u>BTU/lb.</u>	<u>\$/ton</u>	<u>c/10⁶BTUs</u>	<u>BTU/lb.</u>	<u>\$/ton</u>	<u>c/10⁶BTUs</u>
1990 Apr. 12,352	49.38	199.89	12,794	53.70	209.85
May 12,352	49.39	199.94	12,794	53.71	209.89
June 12,352	49.43	200.11	12,794	53.72	209.93
July 12,352	49.81	201.61	12,794	54.20	211.83
Aug. 12,352	49.73	201.30	12,794	54.13	211.55
Sept. 12,352	49.98	202.32	12,794	54.32	212.29
Oct. 12,352	50.29	203.58	12,794	54.79	214.11
Nov. 12,352	50.43	204.14	12,794	54.87	214.43
Dec. 12,352	50.37	203.89	12,794	54.82	214.26
1991 12,366	53.02	214.36	12,806	58.82	229.68
1992 12,368	55.20	223.16	12,716	61.80	243.00
1993 12,365	57.51	232.54	12,628	64.73	256.28
1994 12,362	60.04	242.84	12,613	70.47	279.34
1995 & beyond: escalate with general inflation					

TDP
4/6/90

FUEL & SPECIAL PROJECTS

Special Forecast - Facility Planning Case - Base Case

Natural Gas Price Projections

New Pipeline Source ⁽¹⁾

	BTU/CF	<u>Variable</u> Cents/10 ⁶ BTU	<u>Fixed</u> ⁽²⁾ Cents/10 ⁶ BTU
1994	1,000	355	30
1995	1,000	420	30
1996	1,000	460	30
1997	1,000	510	30
1998	1,000	560	30
1999	1,000	610	30
2000	1,000	680	30

(1) Doesn't include the cost for laterals, meter stations, etc. to plant site. Based on the construction of a new mainline into peninsular Florida with a nominal capacity of 500 x 10⁹ BTU/day. This would require a fixed demand commitment from users for about 400 x 10⁹ BTU/day, (either from Florida Power individually or a combination of customers). Prices assume commitment in 1990 for deliveries to begin in 1994.

(2) Fixed charge set by contract on maximum daily volume required. Billed on a monthly basis for life of contract independent of volume actually used.

TDP
4/6/90

ML93705

FUEL & SPECIAL PROJECTS

Special Forecast - Facility Planning Case - Base Case

#2 Fuel Oil Price Projections

	<u>\$/bbl.</u>	<u>¢/gal.</u>	<u>¢/10⁶BTUs</u> ⁽¹⁾
1990 Apr-Dec.	25.20	60	434.48
1991	25.62	61	441.72
1992	26.46	63	456.21
1993	28.56	68	492.41
1994	31.08	74	535.86
1995	32.76	78	564.83
1996	34.86	83	601.03
1997	36.96	88	637.24
1998	39.06	93	673.45
1999	41.58	99	716.90
2000	43.68	104	753.10

2001 & beyond: escalate with general inflation.

(1) 5.8 (10⁶) BTU/bbl. & 42 gal. per barrel.

TDP
4/6/90

ML93706

FUEL & SPECIAL PROJECTS

Special Forecast - Facility Planning Case - Base Case

Residual Fuel Oil Price Projections

Steam

	2.5%		1.0%		.3% low pour	
	<u>\$/bbl.</u>	<u>¢/10⁶BTU⁽¹⁾</u>	<u>\$/bbl.</u>	<u>¢/10⁶BTU⁽¹⁾</u>	<u>\$/bbl.</u>	<u>¢/10⁶BTU⁽²⁾</u>
<u>1990</u>						
Apr. -	16.00	254.0	18.00	285.7	21.00	355.9
Dec.						
<u>1991</u>	16.00	254.0	19.00	301.6	21.00	355.9
<u>1992</u>	17.00	269.8	20.00	317.5	22.00	372.9
<u>1993</u>	18.00	285.7	21.00	333.3	24.00	406.8
<u>1994</u>	20.50	325.4	23.00	365.1	27.00	457.6
<u>1995</u>	22.00	349.2	26.00	412.7	30.00	508.5
<u>1996</u>	23.00	365.1	28.00	444.4	32.00	542.4
<u>1997</u>	24.50	388.9	29.00	460.3	34.00	576.3
<u>1998</u>	26.00	412.7	31.00	492.1	36.00	610.2
<u>1999</u>	27.50	436.5	33.00	523.8	38.00	644.1
<u>2000</u>	29.00	460.3	34.00	539.7	42.00	711.9

2001 & beyond: escalate with general inflation.

(1) 6.3×10^6 BTU/bbl.

(2) 5.9×10^6 BTU/bbl.

TDP
4/6/90

File
Fuel Cost Projections

FPC FUEL COST PROJECTION FCP9501 - June 1995

- * Previous Forecast (FPC9402) was completed in September 1994.
- * New Forecast (FPC9501) completed May 30, 1995 includes Short (through 3/96) and Long Term Forecasts. Short Term Forecast is for next Fuel Adjustment, Long Term is for planning.
- * Similarities:

1. Cost order (low to high):

Nuclear
CR 1&2 Coal
CR 4&5 Coal
2.5% Oil
1.0% Oil
U of F Gas
Polk Gas
Distillate Oil

2. Gas and Oil are competitive, but gas is generally more expensive (burner tip).

- * Differences:

1. Price differentials between 1% and 2.5% sulfur oil are much narrower. 2.5% Oil is the only fuel that has a higher projected price.
2. Gas and oil price differentials are smaller.
3. All fuel prices (except 2.5% oil) are lower. 2.5% Oil prices are high due to demand as a bunker fuel.

- * Impacts:

1. Lower gas forecast will increase capacity factor on Polk County.
2. Small low/high sulfur oil price differential will impact cost of Clean Air Act compliance.

FLORIDA POWER CORPORATION

Fuel Forecast Comparison FPC9402 Vs. FPC9501

Year	U of F Gas		Polk Gas		High Sulfur Oil		Low Sulfur Oil		Distillate Oil		Crystal River 1 & 2		Crystal River 4 & 5	
	9402 U of F Gas	9501 U of F Gas	9402 Polk Gas	9501 Polk Gas	9402 2.5% Oil	9501 2.5% Oil	9402 1.0% Oil	9501 1.0% Oil	9402 #2 Oil	9501 #2 Oil	9402 CR1&2	9501 CR1&2	9402 CR4&5	9501 CR4&5
1996	2.90	2.49			2.30	2.70	2.72	2.80	4.56	4.30	1.80	1.74	2.09	2.01
1997	3.03	2.61			2.40	2.65	2.84	2.75	4.72	4.30	1.84	1.77	2.14	2.05
1998	3.19	2.71	3.34	2.92	2.51	2.70	2.99	2.80	4.87	4.40	1.87	1.79	2.21	2.08
1999	3.30	2.82	3.46	3.02	2.62	2.85	3.12	2.90	5.03	4.70	1.92	1.83	2.27	2.12
2000	3.41	2.98	3.56	3.19	2.71	2.95	3.23	3.00	5.27	4.90	1.98	1.89	2.34	2.17
2001	3.53	3.14	3.67	3.34	2.79	3.10	3.34	3.15	5.43	5.05	2.03	1.93	2.40	2.23
2002	3.69	3.30	3.83	3.51	2.94	3.20	3.46	3.25	5.59	5.10	2.09	1.97	2.48	2.28
2003	3.85	3.48	4.00	3.66	3.08	3.30	3.58	3.35	5.83	5.25	2.15	2.01	2.53	2.33
2004	4.01	3.62	4.15	3.83	3.17	3.40	3.70	3.45	6.00	5.40	2.21	2.05	2.60	2.37
2005	4.23	3.73	4.36	3.93	3.29	3.45	3.83	3.50	6.31	5.60	2.27	2.09	2.45	2.41
2006	4.33	3.84	4.47		3.39	3.55	3.94	3.61	6.53		2.33	2.13	2.52	2.45
2007	4.46		4.57		3.49		4.06		6.76		2.40		2.59	

Year	U of F Gas		Polk Gas		High Sulfur Oil		Low Sulfur Oil		Distillate Oil		Crystal River 1 & 2		Crystal River 4 & 5	
	9402 U of F Gas	9501 U of F Gas	9402 Polk Gas	9501 Polk Gas	9402 2.5% Oil	9501 2.5% Oil	9402 1.0% Oil	9501 1.0% Oil	9402 #2 Oil	9501 #2 Oil	9402 CR1&2	9501 CR1&2	9402 CR4&5	9501 CR4&5
1996	-0.41		0.00		0.40		0.08		-0.26		-0.06		-0.08	
1997	-0.42		0.00		0.25		-0.09		-0.42		-0.07		-0.09	
1998	-0.48		-0.42		0.19		-0.19		-0.47		-0.08		-0.13	
1999	-0.48		-0.44		0.23		-0.22		-0.33		-0.09		-0.15	
2000	-0.43		-0.37		0.24		-0.23		-0.37		-0.09		-0.17	
2001	-0.39		-0.33		0.31		-0.19		-0.37		-0.1		-0.17	
2002	-0.39		-0.32		0.26		-0.21		-0.49		-0.12		-0.18	
2003	-0.39		-0.34		0.22		-0.23		-0.58		-0.14		-0.20	
2004	-0.39		-0.32		0.23		-0.25		-0.60		-0.16		-0.23	
2005	-0.50		-0.32		0.16		-0.33		-0.71		-0.18		-0.04	
2006	-0.49		-0.43		0.16		-0.33				-0.2		-0.07	
2007														

